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May 28, 2002

VIA FEDERAL EXPRESS

The Honorable Magalie Roman Salas
Office of the Secretary
Federal Energy Regulatory Commission
888 First Street N.E., Room 1A
Washington D.C. 20426

Re: RT01-35-005
Our File No. 071000/126511

Dear Ms. Salas:

Enclosed for filing in above referenced proceeding is an original and 15 copies of:

- The Motion to Intervene of the Public Generating Pool, the Washington Public Utility Districts Association, the Western Public Agencies Group, Public Utility District No. 1 of Snohomish County, Springfield Utility Board, Tacoma Power and the Eugene Water and Electric Board on the Filing Utilities' Stage 2 Filing and Request for Declaratory Order Pursuant to Order 2000.

- Protest of the Public Generating Pool, the Washington Public Utility Districts Association, the Western Public Agencies Group, Public Utility District No. 1 of Snohomish County, Springfield Utility Board, Tacoma Power and the Eugene Water and Electric Board on the Filing Utilities' Stage 2 Filing and Request for Declaratory Order Pursuant to Order

Please date and time stamp the extra copies and return them to me in the enclosed self-addressed, stamped envelope.

Thank you for your assistance in this matter.

Sincerely,

Raymond S. Kindley

Enclosures
cc: Official service list
PGP Operating Committee
PGP Administrative Committee

BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Avista Corporation,	)
Bonneville Power Administration,	)
Idaho Power Company,	)
The Montana Power Company,	)
Nevada Power Company,	) Docket No. RT01-35-005
PacifiCorp,	)
Portland General Electric Company,	)
Puget Sound Energy, Inc., and	)
Sierra Pacific Power Company.	)

Motion to Intervene of the Public Generating Pool, the Washington Public Utility Districts Association, the Western Public Agencies Group, Public Utility District No. 1 of Snohomish County, Springfield Utility Board, Tacoma Power, and the Eugene Water and Electric Board on the Filing Utilities' Stage 2 Filing and Request for Declaratory Order Pursuant to Order 2000

Pursuant to Rule 214 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"), 18 C.F.R. § 385.214 (2000), Public Generating Pool ("PGP"), Washington Public Utility Districts Association ("WPUDA"), the Western Public Agencies Group ("WPAG"), Public Utility District No. 1 of Snohomish County, Springfield Utility Board, Tacoma Power, and the Eugene Water and Electric Board hereby move for intervention in the above-captioned docket. In support of its motion, the Intervenors state as follows:

COMMUNICATION INFORMATION

Communications and correspondence regarding this proceeding should be directed to:

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INTERVENORS

PGP is a non-profit, voluntary association of five publicly-owned utilities located in the state of Washington. Its members are the Public Utility District No. 1 of Cowlitz County, Public Utility District No. 1 of Douglas County, Public Utility District No. 2 of Grant County, Public Utility District No. 1 of Pend Orielle County and The City of Seattle, City Light Department. PGP members own and operate federally licensed hydroelectric projects located in the state of Washington.

WPUDA is a non-profit, voluntary association of publicly-owned utilities also located in Washington. The electric utility members of WPUDA are Asotin, County PUD, Benton County PUD, Chelan County PUD, Clallam County PUD, Clark Public Utilities, Cowlitz County PUD, Douglas County PUD, Ferry County PUD, Franklin County PUD, Grant County PUD, Grays Harbor County PUD, Kittitas County PUD, Klickitat County PUD, Lewis County PUD, Mason County PUD No. 1, Mason County PUD No. 3, Okanogan County PUD, Pacific County PUD, Pend Oreille County PUD, Skamania County PUD, Snohomish County PUD, Wahkiakum County PUD and Whatcom County PUD. WPUDA members own and operate power projects located in the state of Washington.

The Western Public Agencies Group is comprised of Alder Mutual Light Company, Benton Rural Electric Association, City of Cheney, City of Ellensburg, City of Fircrest, City of Milton, City of Port Angeles, Elmhurst Mutual Power and Light Company, Lakeview Light and Power Company, Ohop Mutual Light Company, Parkland Light and Water Company, Peninsula Light Company, Public Utility District No. 1 of Clallam County, Washington, Public Utility District No. 1 of Clark County, Washington, Public Utility District No.1 of Kittitas County, Washington, Public Utility District No. 1 of Lewis County, Washington, Public Utility District No. 1 of Mason County, Washington, Public Utility District No. 3 of Mason County, Washington, Public Utility District No. 2 of Pacific County, Washington, Public Utility District No. 1 of Snohomish County, Washington, Town of Eatonville, and

Town of Steilacoom. WPAG members own and operate power projects located in the state of Washington.

The Springfield Utility Board, the Eugene Water and Electric Board and Tacoma Power are the publicly-owned utilities for the cities of Springfield, Oregon, Eugene, Oregon, and Tacoma, Washington respectively.

Intervenors trade extensively in power markets in the Pacific Northwest, and greatly rely on the transmission facilities located in the Pacific Northwest for their power transactions.

BACKGROUND OF PROCEEDING

Avista Corporation, Bonneville Power Administration, Idaho Power Company, The Montana Power Company, Nevada Power Company, PacifiCorp, Portland General Electric Company, Puget Sound Energy, Inc. and Sierra Pacific Power Company ("Filing Utilities") submitted to the Commission on March 29, 2002 its Stage 2 Filing and Request for Declaratory Order pursuant to Order No. 2000. The Filing Utilities propose to form a regional transmission organization in the Pacific Northwest and sections of the Southwest. The Filing Utilities refer to the proposed organization as RTO West. The Filing Utilities want the Commission to decide that various aspects of their proposal, i.e., scope, configuration and governance documents, comply with Order No. 2000.

INTERVENORS' INTERESTS

Intervenors rely on transmission facilities owned and operated by the Bonneville Power Administration and other Filing Utilities in the Pacific Northwest to deliver and receive power. They have long-term agreements with various members of the Filing Utilities for transmission service. Also, they are periodically competitors of the Filing Utilities in the Pacific Northwest.

Intervenors participated in the public processes regarding the development of RTO West either individually or on behalf of their members. The Commission's disposition of the Filing Utilities' requests will have a direct and substantial impact on the interests and operations of Interventors. Interventors individually or through their memberships have decided to intervene jointly for administrative convenience and to reduce costs.

The individual members of PGP, WPUDA, and WPAG intend to rely on their association to represent their common interests in this proceeding. Each member, however, is a party of interest in its own right and wants to preserve its independent status and interests as an individual intervening party. Therefore, Intervenors submit this intervention on the collective behalf and their respective members in this proceeding and declare that such intervention is in the public interest.

WHEREFORE, Intervenors move the Commission to grant their invention.

Dated this 28th day of May, 2002.

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Attorney for WAPG

CERTIFICATE OF MAILING (SERVICE LIST)

I HEREBY CERTIFY that I have this day served the foregoing, MOTION TO INTERVENE OF THE PUBLIC GENERATING POOL, the WASHINGTON PUBLIC UTILITY DISTRICTS ASSOCIATION, the WESTERN PUBLIC AGENCIES GROUP, PUBLIC UTILITY DISTRICT NO. 1 OF SNOHOMISH COUNTY, SPRINGFILED UTILITY BOARD, TACOMA POWER, and the EUGENE WATER and ELECTRIC BOARD on the FILING UTILITIES' STAGE 2 FILING and REQUEST FOR DECLARATORY ORDER PURSUANT TO ORDER 2000 to be served by First Class Mail upon each party designated on the official service list compiled by the Secretary of the Commission in this proceeding.

DATED at Portland, Oregon, this 28th day of May, 2002.

Raymond S. Kindley

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Avista Corporation,	)
Bonneville Power Administration,	)
Idaho Power Company,	)
The Montana Power Company,	)
Nevada Power Company,	) **Docket No. RT01-35-005**
PacifiCorp,	)
Portland General Electric Company,	)
Puget Sound Energy, Inc., and	)
Sierra Pacific Power Company.	)

Protest of the Public Generating Pool, the Washington Public Utility Districts Association, the Western Public Agencies Group, Public Utility District No. 1 of Snohomish County, Springfield Utility Board, Tacoma Power, and the Eugene Water and Electric Board on the Filing Utilities' Stage 2 Filing and Request for Declaratory Order Pursuant to Order 2000

The Public Generating Pool, Washington Public Utility Districts Association, the Western Public Agencies Group, Public Utility District No. 1 of Snohomish County, Springfield Utility Board, Tacoma Power, and the Eugene Water and Electric Board ("Protestants")[1] jointly and individually protest the Stage 2 Filing and Request for Declaratory Order Pursuant to Order 2000, submitted to the Federal Energy Regulatory Commission (the Commission) on March 29, 2002,[2] in this docket by Avista Corporation, Bonneville Power Administration, Idaho Power Company, The Montana Power Company, Nevada Power Company, PacifiCorp, Portland General Electric Company and Sierra Pacific Power Company (collectively, the Filing Utilities). Protestants file this Protest

[1] A complete listing of the Protestants and their memberships is listed on Exhibit 9 hereto.

pursuant to Rule 211 of the Commission's Rules of Practice and Procedure, 18 CFR §§ 385.211, and pursuant to the Commission's Notice of Extension of Time dated April 17, 2002, in these dockets.

Protestants consist of 41 consumer-owned utilities in Washington and Oregon, who collectively serve over 1.5 million retail consumers, with over 50 million kwh in retail sales for $2 billion in revenues, an additional 25 million mwh of wholesale sales, and approximately 8,300 MW of generation capacity. Protestants range in size from 2000 customers to 350,000 customers, and include municipal utilities, public utility districts, mutuals and cooperatives. Protestants have been involved in the public discussions regarding the development and formation of RTO West since the very beginning. After much deliberation, Protestants have reached the conclusion that the RTO West proposal, currently in Stage 2 of its development, is fundamentally flawed and incapable of yielding benefits to consumers, and is thus contrary to the fundamental purposes of the Federal Power Act.

Protestants are, however, open to the possibility that cost-effective, incremental improvements can be made to the existing power system in the Northwest, relying in the first instance on modifications to the operations of existing institutions. If necessary, new multi-lateral agreements could be put into place to support greater cooperation on planning, enhanced reliability, and simplification of transactions. Protestants' opposition to RTO West should not be misinterpreted to mean opposition to all change. Rather, Protestants support changes that build on existing institutions, preserve those parts of the system that work well, make improvements in a cost-effective manner, and minimize risks to reliability. <u>The bottom line is that change must benefit consumers.</u> More modest ambitions may succeed where RTO West clearly fails. The following sections of this Protest set forth the many foundations for our basic conclusion that RTO West is not in the interest of consumers, and therefore cannot and should not be approved.

I. THE RTO WEST STAGE TWO PROPOSAL WILL CAUSE ECONOMIC HARM TO CONSUMERS

A. The RTO West Stage 2 Proposal Will Force Consumers to Pay Higher Rates for Delivered Power

When a reasonably complete and relatively conservative accounting of the costs is assembled, it is clear that consumers in the Northwest would pay higher rates due to RTO West, perhaps as much as $450 million higher each year than would be the case without RTO West. This accounting includes the potential for modestly lower production (generation) costs, but also takes into account the costs of setting up and running RTO West itself, new Scheduling Coordinator and energy exchange costs, new metering costs, new transactions costs, additional return-on-equity for investor-owned utilities, and new state and local taxes. The analysis is conservative because it does not attempt to quantify (a) the risks that RTO West will experience the kinds of costs experienced at the California ISO, (b) the risks of market power, (c) the risks of reduced reliability, (d) new insurance costs, and (e) the costs of meeting new credit standards. Nor does this accounting include any non-quantified benefits, because they are highly speculative and, *per se*, unquantifiable.

B. The Commission Is Required by Statute and Case Law, as Well as Broad Public Policy, to Ensure that Consumers Are Not Harmed

The purposes espoused by the Commission in Order 2000 are laudable: efficient and reliable operations, continued development of competitive electricity markets, and lower prices. *See* Order 2000 at 2-3.[3] In the same Order, the Commission has recognized its responsibilities under §205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d: "ensure that rates, terms and conditions of transmission and sales for resale in interstate commerce by public utilities are just, reasonable and not unduly discriminatory or preferential". *Id.* at 5. The Commission goes on to emphasize the importance of competitive bulk power markets. *Id.* at 9-10. The entire structure of Order 2000 rests on these important objectives. However, there is no guarantee that any specific institutional structure would achieve these objectives, so the Commission has provided for "significant flexibility" in responding to Order 2000. *Id.* at 91. The RTO West Stage 2 proposal offers an important opportunity for the Commission to return to the principles of the Federal Power Act, by rejecting a proposal that would interfere with efficient and reliable operations, would interfere with the development of competitive power markets, would impose new costs, and thus would harm consumers by raising the price of delivered power.

Under the FPA, the Commission's fundamental duty is to protect electric ratepayers from potential and actual abuse at the hands of monopolist utilities. Hence, in considering proposals brought forward by regulated utilities, FERC is bound to "ensure that consumers pay no more than a reasonable rate." *Indiana Municipal Power Agency v. FERC*, 56 F.3d 247, 253 (D.C. Cir. 1995); and *Tejas Power Corp. v. FERC*, 908 F.2d 998, 1003-04 (D.C. Cir. 1990) (FERC must "determine whether any benefits or harm might accrue" to consumers).

More specifically, Order No. 2000 requires that the RTO West Stage 2 filing be considered under FPA Sections 203, 205, and 206, 16 U.S.C. §§ 824b, 824d, 824e. Under

[3] References to the page numbers of Order 2000 are to the Slip Opinion

Sections 203 and 205, the utility advocating a change in rates, conditions of service, or ownership of facilities bears the burden of demonstrating that the proposed change is in the public interest. *Villages of Chatham v. FERC*, 662 F.2d 23, 27-33 (D.C. Cir. 1981) (discussing Section 205); *Northeast Utils. Service Co. v. FERC*, 993 F.2d 937, 944 (1st Cir. 1993) (discussing Section 203). Similarly, where FERC requires a change in rates or conditions of service under Section 206, FERC bears the burden of demonstrating that the proposed change is in the public interest. *Cities of Campbell v. FERC*, 770 F.2d 1180, 1184-1185 (D.C. Cir. 1985). "The unifying principle" of these sections "is that the proponent of change bears the burden" of proving that the change is in the public interest. *Public Service Comm'n of New York v. FERC*, 866 F.2d 487, 488 (D.C. Cir. 1989).

The RTO West filing is deficient because it lacks any showing that the RTO will provide "benefits to existing classes of ratepayers" in the RTO West region *(Process Gas Consumers Group v. FERC*, 930 F.2d 926, 931 (D.C. Cir. 1991)), and the Filing Utilities have failed to meet their burden of demonstrating that the radical change of the regional transmission system they propose is in the public interest. On the contrary, as demonstrated herein, RTO West would increase costs to electric consumers far beyond any benefits it would provide. Hence, the Commission must reject the RTO West filing because it fails to meet FERC's professed goal of "protect[ing] the public interest and ensur[ing] that consumers pay the lowest price possible for reliable service."[4]

The D.C. Circuit has left no doubt about the Commission's duty to consider the costs and benefits of RTOs to electric consumers. In defending Order No. 2000 in the D.C. Circuit, the Commission's Solicitor conceded that FERC must consider evidence of

[4] Order 2000 at 3.

whether an RTO in the Northwest would be beneficial to electric consumers in that region. The court accordingly concluded that "the Commission must – in order to comply with the Federal Power Act and the Administrative Procedure Act – adequately address . . . specific cost-benefit evidence . . . prior to the Commission's final decision on the RTO proposal for the Pacific Northwest." *Public Utility District No. 1 of Snohomish County v. FERC*, 272 F.3d 607, 619 (D.C. Cir. 2001) (citations omitted). Indeed, if the Commission fails to address the "difficult or inconvenient facts" demonstrating that the costs of an RTO in the Pacific Northwest may far outweigh its potential benefits, its orders "must crumble for want of substantial evidence." *Tenneco Gas v. FERC*, 969 F.2d 1187, 1214 (D.C. Cir. 1992).

In order to implement the expectations of the Court, the Commission must consider relevant and available evidence. The Filing Utilities have chosen not to present evidence of the costs and benefits of RTO West in their Stage 2 filing, but this omission does not relieve the Commission of its responsibilities. The evidence presented here demonstrates that RTO West would cost consumers more than it would benefit them: rates for delivered power would increase as a result of the formation and operation of RTO West. The Commission should not as a matter of policy, and cannot as a matter of law, give any approvals, conditional or otherwise, to the Stage 2 proposal for RTO West.

C. The Nature of the Electric Power System in the Pacific Northwest Makes It Unlikely That RTO West Can Produce Significant Improvements Over the Existing System

Given the nature of the electric transmission system in the Northwest, the gross benefits of any RTO are likely to be minimal at best when compared to other parts of the country. An RTO offers few benefits in the Pacific Northwest because most of the efficiencies an RTO might theoretically be able to capture (albeit at considerable cost) have already been realized in this region, for several reasons.

First, BPA owns approximately 75% of the transmission system in the Pacific Northwest. The transmission system in the Northwest is not balkanized, as in other regions, and the problems typically associated with balkanization (rate pancaking, inefficiencies in transmission planning and expansion, and the like) do not cause noticeable economic consequences in the Pacific Northwest. In these circumstances, it would be arbitrary and capricious for the Commission to impose an ill-fitting, one-size-fits-all nationwide approach on the Pacific Northwest. *Interstate Natural Gas Ass'n of America v. FERC*, 285 F.3d 18, 37 (D.C. Cir. 2002)("the Commission cannot enact 'an industry-wide solution for a problem that exists only in isolated pockets. In such a case, the disproportion of remedy to ailment would, at least at some point, become arbitrary and capricious.'" (citation omitted)).

Second, the Pacific Northwest has a long tradition of cooperative planning on a "one-system" basis and regional cooperation on a host of other issues related to the transmission grid, including a regional system of coordination of planned outages through the Northwest Power Pool ("NWPP"); a system of coordinated operation of generation through the Pacific Northwest Coordination Agreement ("PNCA"), the Mid-Columbia Hourly Coordination Agreement ("MCHC"), and related treaty and non-treaty obligations with Canadian arising under the Columbia River Treaty; sharing of reserves between the region's control areas; and coordination of control areas for reliability purposes through the Pacific Northwest Security Coordinator Agreement ("PNSCA").

Third, the Northwest is blessed with an abundance of hydroelectric energy, which is used on a regular and coordinated basis to minimize the cost of generation by displacing more expensive thermal resources. This displacement occurs in all existing energy markets, including operating reserves.

Accordingly, there are relatively few productive efficiencies available to RTO West that have not already been captured through the cooperative efforts of BPA and other established market participants. While the regional transmission system is not perfect, it is obvious that it would be far more cost effective and less risky to improve existing institutions to achieve the goals of Order 2000, rather than tearing down the entire system built up over the last 70 years in the Pacific Northwest and attempting to rebuild it from the ground up. The Commission cannot ignore the current system in determining whether changes are required and in the public interest.

D. The ICF Study for FERC Fails to Provide a Rationale for RTO West

In Order No. 2000, FERC conceded that "the level of RTO benefits may vary from region to region depending on the current transparency and efficiency of markets." Order No. 2000 at 89. However, the Commission has made no attempt to evaluate the costs and benefits of RTOs on a region-by-region basis and, to this point, has failed even to acknowledge substantial record evidence in previous RTO-related proceedings suggesting that an RTO in the Pacific Northwest may have minimal benefits.[5] Indeed, FERC undertook its RTO initiative based upon "entirely anecdotal evidence" that continuing discrimination by transmission owners could be a problem, "without the benefit of any

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[5] *See PUD No. 1 of Snohomish County v. FERC*, 272 F.3d at 618 (noting that the Commission did not address Northwest-specific evidence in the Order No. 2000 rulemaking docket).

substantive analysis showing that the agency's new measures will be beneficial for consumers," and without evidence showing that "the RTO model will be successful."[6] It would be both poor public policy and a serious abuse of discretion for FERC to embark on a radical restructuring of one of the nation's fundamental industries on such a thin record.

In the absence of any prior evidence, FERC commissioned a study by ICF Consulting (issued on February 26, 2002), to justify or provide support for its RTO policy.[7] The ICF Study, however, contains a wide variety of conceptual and methodological errors, rendering it useless as a basis for assessing the economic impacts of RTOs. Protestants agree with the conclusion of the Tellus Institute:

> The ICF study does not allow one to conclude anything useful about the full range of potential costs and benefits of RTO formation. . . . The study is very selective concerning which aspects of RTOs are analyzed versus those which are not analyzed, and several of the key assumptions regarding the potential impact of RTO formation relative to the Base Case have no justification whatsoever. A single unrealistic assumption, the heat rate improvement assumption, appears to account for more than 80 percent of the savings attributed to RTO formation. Also, many of the benefits claimed for RTO formation could be achieved through other regulatory policy approaches, such as traditional power pool formation and least cost planning . . . Most of the key assumptions that the study makes to define Transmission Only and the RTO Policy scenarios are highly questionable, and some of these assumptions are entirely unrelated to RTO formation.[8]

Another review of the ICF Study similarly concludes:

> [T]he major deficiency of FERC's Economic Assessment is that it is not a cost-benefit analysis of RTOs. As a result, it

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[6] Thomas M. Lenard, "RTOs, Market Power and the New Regulatory Agenda at the FERC," Progress on Point Release No. 9.4, February 2002, at 3, 6, 14 (available at www.pff.org/publications/pop9.4rtos.pdf).
[7] ICF Consulting, "Economic Assessment of RTO Policy," Feb. 26, 2002 ("ICF Study").
[8] Richard A. Rosen, John Stutz & Freyr Sverrisson, "Tellus Review of FERC's Economic Assessment of RTO Policy," April 5, 2002, at 1-2.

> bypasses the basic questions about RTOs that need to be addressed. The Economic Assessment assumes that the objectives of the RTO structure as enumerated in FERC's discussion of Order No. 2000—essentially that markets will be more competitive and more efficient—will be achieved and then goes on to estimate, using additional assumptions, what those benefits will be. There is no discussion of the incentive questions raised by the RTO structure. There is also no discussion or evaluation of the real-world experience of existing RTO-like entities, such as the ISOs in California and the Northeast. In fact, the FERC analysis explicitly assumes that existing ISOs (California, PJM, New York and New England) have no market inefficiencies.[9]

Further, even taken at face value, the benefits that the ICF Study attributes to RTOs are "miniscule compared to the U.S. national electric bill."[10] Some of the parties to this Protest have independently participated in submitting comments to FERC on the ICF Study, which are incorporated herein by reference.[11]

Finally, for a variety of reasons, the ICF Study contains no useful information about the effects of an RTO on the Pacific Northwest specifically. First, the ICF Study assumes that the electricity market on the West Coast ends at the U.S.-Canada border, and it therefore ignores the major sources of generation located in British Columbia and Alberta that serve the Western markets. Second, the ICF Study relies upon a locational marginal cost methodology that does not permit incorporation of unique characteristics of a hydro-based system such as that of the Pacific Northwest.

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[9] Thomas M Lenard, FERC's Assessment of the Benefits and Costs of Regional Transmission Organizations, Progress on Point No. 9.8, February 2002, at 4 (available at www.pff.org/publications/PoP9.8FERCRTO.pdf).

[10] Rosen *et al.*, *supra* note 7 at 1.

[11] See the comments of the Large Public Power Council and the Public Generating Pool on the ICF study, filed in Commission Docket No. RM01-12-000.

E. Based on the Evidence, RTO West Will Cause Economic Harm to Consumers

A simple bottom line should drive Commission decisions on RTO West: will consumers be better off? On this important test, the RTO West Stage 2 proposal very clearly and very badly fails. Unlike other RTO proposals, the Commission has before it in this docket a cost-benefit study that, although flawed, provides evidence of some of the costs and benefits of RTO West. This study, when corrected and supplemented with the information herein, shows that RTO West will increase the cost of delivered power.

Given that the ICF study is not relevant to RTO West, and the lack of any information provided by the Filing Utilities to the Commission to date, additional evidence on the potential costs and benefits of RTO West itself is required for the Commission to adhere to its responsibilities under law. This Protest provides such evidence.

1. The Tabors Caramanis Study Is Flawed

In 2001, the RTO West Filing Utilities contracted with Tabors Caramanis & Associates (TCA) to conduct an analysis of some of the costs and benefits of the RTO West proposal. The "Final Report Presented to RTO West Filing Utilities" ("TCA Final Report") was delivered on March 11, 2002. The Final Report, including its Attachments 1-5, is provided as Exhibit 1 to this Protest. Between March 11 and late April 2002, Protestants and other entities in the Northwest engaged in clarifications of the Final Report with representatives of the Filing Utilities and TCA. As a result of these clarifications, Protestants discovered several errors in the TCA analysis; these errors collectively have led to biases in the cost-benefit results in favor of RTO West. In addition, the TCA Final Report is an incomplete description of the costs and benefits of the current proposal for RTO West. Additional information on the expected costs and benefits of RTO West must be considered before a complete picture of the impacts on consumers can be constructed. Once the errors in the TCA Final Study are corrected and the additional costs fully considered, it is clear that RTO West will fail the basic test of providing benefits to consumers: the costs of RTO West will clearly exceed the benefits. Thus, the RTO West Stage 2 filing must be rejected as a basic violation of the FPA.

a. The Tabors Caramanis Study Reaches Inaccurate Conclusions that Do Not Reflect the Operations of the Northwest Electrical System

TCA conducted an "Energy Impact Analysis", which estimated benefits in two areas: lower operating costs and reduced transmission system congestion. *See* TCA Final Report at vii. The Energy Impact Analysis concluded that formation of RTO West would reduce production costs by $239 million per year, and reduce congestion costs by $171 million per year. *Id.* The TCA Final Report reached three broad conclusions:

- Generally, the domination of the northwest [sic] system by hydroelectric power provides a relatively efficient bulk power system to begin with;
- Pancaking therefore has a greater impact on the congestion prices across constraints than it does on overall production cost efficiency;
- The ability to further substitute hydro resources for thermal resources for operating reserves, through further regionalization, offers significant benefits.

TCA Final Report at viii.

As the following section demonstrates, TCA's second broad conclusion is not relevant to the calculation of the costs borne by consumers under current (i.e., "without RTO") operations, and the third broad conclusion is undermined by errors in the analysis of operating reserves in the "without RTO" case. When these problems are taken into account, we are left with the sole conclusion that the bulk power system in the Northwest is "relatively efficient . . . to begin with." This relative efficiency sets a high threshold of proof for RTO West, and for the Commission, in any proposal or decision to impose massive structural changes on the region.

b. The Tabors Caramanis Study Mischaracterizes the "Without RTO" Case

There are two problems of mischaracterization of costs borne by consumers in the "without RTO" case in the TCA Final Report. These problems are critical, because if the "without RTO" costs are overstated, the estimated benefits of the "with RTO" case will also be overstated. In other words, mischaracterization of the costs in the "without RTO case" will cause the formation and operation of RTO West to appear to provide more benefits than is reasonable or realistic, thus mistakenly justifying RTO West. When these mischaracterizations are fully understood and corrected, it is clear that the benefits of RTO West are overstated in the TCA Final Report.

First, the "congestion costs" as described in the TCA Final Report do not reflect estimates of payments actually made by consumers in the "without RTO" case. As TCA points out, "[i]f users were required to pay for the marginal cost of congestion rather than only average or incremental cost, as is the case at present, the costs they incurred would be $171 million less with RTO West than without." TCA Final Report at vii-viii (emphasis added). This statement demonstrates that "avoided congestion costs" are an artifact of the computer modeling techniques employed by TCA, and not a reflection of reality. However, even if users were required to "pay for the marginal cost of congestion", such payments would represent transfers of economic rents from consumers to producers, not actual economic costs. Any reduction in such rents payments does not represent a real economic savings to society, because productive efficiency is not affected by the transfer of economic rents.

"Transfer payments are simply changes in who has the right to consume goods. . . . Transfer payments affect the way in which society's total income is divided among its members, but . . . transfers do not affect the total amount of private goods that can be enjoyed." (J.E. Stiglitz, "Economics of the Public Sector", 2nd ed., W.W. Norton & Co., N.Y., at 36-37.) TCA's Energy Analysis concludes that $171 million in hypothetical transfer payments would be reduced due to the formation and operation of RTO West. Even if these reductions were not hypothetical and mere artifacts of the computer model, such transfer payments simply redistribute income among participants in energy markets: some participants (consumers and/or shareholders) might be better off due to RTO West, but only if others (consumers and/or shareholders) are worse off (and only if the system "without RTO West" uses an LMP approach to congestion management that is not currently in place).

Transfer payments should not be considered as part of the basis for an administrative decision. In *The Izaak Walton League of America v. Marsh*, 655 F.2d 346 (D.C. Cir. 1981), the Court upheld a Corps of Engineers' determination that "transfer payments do not represent a real loss to the national economy." *Id.* at 379. In the case at issue, the Corps of Engineers addressed a complaint that railroads would suffer a loss of revenue by noting that such a loss would simply be a transfer payment. The Court agreed with the Corps that transfer payments – specifically revenue that would be earned by barges and not railroads – should not be considered in the evaluation of the costs and benefits for a new dam and lock. *Id.* Likewise, in the present case the Commission should not consider "avoided congestion costs", even if they were not hypothetical, because such costs are transfer payments.

The Commission should only take into account the likely effects on electricity consumers as a whole. It would be bad public policy for the Commission to use redistributions of income as the basis for any decision to approve RTO West. Therefore, the Commission should eliminate such redistributive effects from the evidence on which its decisions are based. (The likely effects on consumers of higher state and local taxes, discussed below, must be taken into account by the Commission even though taxes are generally also considered transfer payments, because the Commission's statutory mandate is to protect electricity <u>consumers</u>, and the additional state or local taxes would transfer income away from electricity consumers to other members of society. It would be bad <u>energy</u> policy for the Commission to approve a proposal that has such an effect.)

In the analysis commissioned by RTO West, TCA did not attempt to estimate <u>actual</u> congestion costs, but rather used a computer model to estimate <u>hypothetical</u> congestion costs, under the assumption that the "without RTO" case is characterized by a Locational Marginal Price (LMP) congestion management system. However, there is no such LMP system in place in the Northwest today, and even if there were such a system in place, payments of economic rents do not affect productive efficiency. There is in fact no estimate in the TCA Final Report of what <u>actual</u> congestion costs are without RTO West; in addition, there is no evidence generally available from any known source on what <u>actual</u> congestion costs are without RTO West, and there is no evidence available on how <u>actual</u> congestion costs might change due to the formation and operation of RTO West. The $171 million in "avoided congestion costs" must be eliminated from the cost-benefit equation, because it does not represent real costs that consumers will avoid due to the formation and operation of RTO West. The Commission cannot rely on purely hypothetical and speculative estimates of "avoided costs" to approve RTO West.

Second, the TCA Energy Anaylsis implements a misunderstanding of the way operating reserves are currently provided in the Pacific Northwest without an RTO. Because of the dominance of hydroelectric energy in the region, most utilities in the Northwest rely almost exclusively on hydroelectric resources for operating reserves. TCA made two critical assumptions about the availability of hydroelectric energy to provide operating reserves, which collectively serve to underestimate the amount of reserves provided by hydropower, thus overstating the potential benefit of changing the dispatch of thermal resources in the provision of operating reserves. First, TCA assumed that operating reserves are carried on each individual company's generating units. *See* TCA Final Report at 8. The detailed implications of this assumption were clarified during a conference call on March 20, 2002, attended by representatives of RTO West, TCA, Filing Utilities, and other entities, including Protestants. Specifically, TCA stated that the shares of non-federal hydroelectric projects that are under contract for sale to Northwest investor-owned utilities (IOUs) were excluded from the set of resources available to provide reserves in the "without RTO" case. (*See* Exhibit 4 to this Protest). These contractual shares are normally relied on by IOUs to meet their operating reserve requirements. The exclusion of these contractual shares of hydro resources means that the availability of hydro resources to meet regional reserve requirements was understated in the "without RTO" case, thus overstating the reliance on thermal resources and overstating the potential benefits of a hypothetically more efficient dispatch of thermal reserves.

Second, based on (perhaps misunderstood) input from BPA, TCA assumed that only 20 percent of unloaded hydro resources can be used to meet spinning reserve requirements in the "without RTO" case. *See* TCA Final Report at 12. This assumption is unrealistically low, for two reasons. (a) It is reasonable to conclude that TCA and BPA have miscommunicated on the nature of the "20% rule", because TCA applied the 20% limit to the amount of unloaded hydroelectric capacity, whereas BPA's calculation of a fixed hydro schedule was based on the assumption that 20% of total hydroelectric capacity is available for reserves. *See* Exhibit 4 to this Protest. (b) Normal operation of the region's hydroelectric resources means that most, if not all, of the unloaded portion of hydroelectric generation can respond to disturbances and deliver operating reserves. Again, the conclusion is clear: to the extent that the availability of hydro resources to provide operating reserves is understated in the "without RTO" case, the reliance on thermal resources will be overstated, and the potential benefits of RTO formation will also be overstated. Together, these two critical assumptions lead to erroneous conclusions regarding the productive efficiency of the Northwest's power system without RTO West, and result in an overstatement of the potential for efficiency improvements due to RTO West.

A rough estimate of the impact of the mischaracterization of operating reserves is available from one of the sensitivity runs conducted by TCA for the Filing Utilities. When the operating reserve requirement is set to zero in both the "with" and "without" RTO cases, the generation cost savings associated with RTO West fall by $150 million. See Exhibit 6 to this Protest. This suggests that redispatch of thermal resources to supply operating reserves accounts for the majority of the improvement in productive efficiency attributed to RTO West.

c. The Tabors Caramanis Study Makes Inappropriate and Inaccurate Assumptions that Bias the Energy Analysis in Favor of RTO West

In addition to the above problems, there are other critical and unrealistic assumptions in the TCA Final Report, which further bias upward the estimated benefits of RTO West.

First, TCA assumed that Northwest utilities schedule maintenance in an economically inefficient manner, by ignoring market prices. TCA's description of maintenance scheduling does not include any consideration of market prices, but instead assumes that maintenance scheduling is tied to each utility's loads. See Exhibit 1 to this Protest at 13. When questioned about this assumption, TCA's response was that "this is how maintenance is scheduled in the East". Even if this description of Eastern practices is accurate, it is not relevant in the Northwest, where utilities regularly schedule maintenance to minimize the net cost of purchasing power on the short-term market and to take advantage of the seasonal surge in hydropower production associated with the spring runoff. This assumption overstates the benefits of RTO West, by underestimating the efficiency of the Northwest system without RTO West. A rough estimate of the impact of the mischaracterization of scheduled maintenance is available from one of the sensitivity runs conducted by TCA for the Filing Utilities. When the same maintenance schedule is used for both the "with" and "without" RTO cases, the generation cost savings associated with RTO West fall by $27 million. See Exhibit 6 to this Protest.

Second, TCA modeled transmission losses in the Energy Analysis in a manner that appears to create a benefit from RTO West when in fact these costs would be shifted from one manner of collection to another. In the "without RTO" case, TCA assumed that most transactions face a charge for transmission losses. *See* Exhibit 1 to this Protest at 10. In the "without RTO" case, TCA removed this charge for transmission losses from the dispatch algorithms for transactions within two subregions of RTO West (B.C. Hydro and the rest of RTO West). *Id.* This theoretically reduced the perceived cost of transmission and permitted more efficient dispatch. However, this removal of transmission losses for transactions within RTO West subregions does not mean that these costs disappear, it merely means that these costs must be collected from consumers through a different mechanism. The exclusion of these shifted costs from the analysis leads to an overstatement of the expected benefits of RTO West, because a cost that would be paid by consumers in the "with RTO" case is overlooked or omitted from the analysis.

Third, TCA made an incorrect assumption about the existence of long-term contracts for the transmission of distant generation to load. These contracts reduce the actual marginal cost of transmission for these generation resources, when they are "on the margin", below the cost assumed by TCA. TCA assumed that new generation resources, even those assumed to be in operation in 2004, will not rely on long-term transmission contracts that make the fixed cost of transmission "sunk" and thus irrelevant to dispatch. *See* Exhibit 4 to this Protest. This overstatement of marginal transmission costs reduces the efficiency of generation dispatch in the "without RTO" case, raises the LMPs in the Energy Analysis, and thus overstates the benefits of the formation and operation of RTO West.

Given the limited information made available by RTO West and the Filing Utilities, it is difficult to quantify the total impact of these errors. An attempt has been to do so, as noted above, in the interest of estimating the order of magnitude of the errors, using the results of sensitivity analyses conducted by TCA. The sensitivity analyses suggest that these errors may be sufficient to erase all of the estimated reductions in production costs and "avoided congestion costs" that have been attributed to RTO West. This result should not be surprising, given the first conclusion of TCA cited above: "[g]enerally, the domination of the northwest [sic] system by hydroelectric power provides a relatively efficient bulk power system to begin with". We recognize that these sensitivity results are only suggestive, but they clearly indicate that the estimated "benefits" of RTO West have been overstated, perhaps significantly.

2. Based on Data in the Tabors Caramanis Study, the Gross Benefits from RTO West Are Negligible, and the Net Benefits are Negative

When the "avoided congestion costs" are removed from the TCA estimate of net benefits, there remains only the estimated \$239 million in lower annual production costs. As noted above, this estimate is overstated, perhaps by as much as \$177 million, leaving perhaps only \$62 million in lower production costs. Assuming (per TCA) that the total loads in RTO West are 31,350 aMW, this means that each kWh of consumption in the RTO West area would receive a reduction in price of \$0.0002. If the average retail rate in the region is 5 cents/kWh, this potential gross benefit represents less than one-half of one percent.

However, this even modest benefit does not count the minimum costs of RTO operation listed in the TCA Final Study, including \$127 million in costs for RTO West itself, \$17 million in new Scheduling Coordinator costs, and \$27 million in new costs of operating transmission and energy exchanges: a total of \$171 million in new costs. Even before consideration of costs that TCA did not address, RTO West shows a net cost to consumers of over \$100 million per year. *See* Exhibit 6 to this Protest.

3. The TCA Energy Analysis Only Tells Part of the Story

In addition to the problems identified above, the TCA Energy Analysis provides an incomplete picture of the costs and benefits of RTO West, because it does not address several other areas of new costs that would be triggered by the formation and operation of RTO West.

a. The costs of set-up and operations of RTO West may easily exceed the range identified in the TCA Final Report

The TCA study concluded that the costs of setting up and operating RTO West itself would fall in the range of $127 million to $143 million per year. *See* TCA Final Report at 39. This conclusion is overly optimistic, because it does not adequately take into account the history of the California ISO. To appropriately account for the risk of cost overruns, the upper end of the potential range of RTO West costs should not just average in the Cal-ISO costs, which were $0.84/MWH in 2001 according to TCA (TCA Final Report at 38), and are estimated to be $0.90 in 2002 (Fortnightly's Grid Week, Letter No. 12, April 19, 2002, increasing the $.084/MWH charge cited by TCA by the ratio of the 2002 revenue requirement to the 2001 revenue requirement). If RTO West's costs overrun TCA's most optimistic estimate by 50 percent, the result would still only be three-quarters of the (unit) costs of the California ISO for 2002. Thus, a complete accounting of risks should consider the possibility that the costs of RTO West itself could overrun the optimistic estimate by $64 million/year.

b. New costs will be borne by consumers to meet the Scheduling Coordinator requirements of RTO West

RTO West would require the formation of Scheduling Coordinators. This service cannot be expected to be provided for free. The TCA Final Report cites a potential cost of

$0.0625/MWH to $0.08/MWH. The difference between these two would add $5 million in new costs.

c. New metering will be required at all the nodes in the RTO West system

Although the RTO West scheduling and billing systems have not been outlined, let alone designed or constructed, the likelihood of additional metering costs is discussed in the Stage 2 filing (*see* Filing Letter, Attachment J-6 at 2-3). The "proposed strategy" to address certain risks includes "Minimum Metering Requirements". These metering requirements are described as leading to increased costs of participating in RTO West, but the Stage 2 filing does not include estimates of these costs. According to data obtained from TCA, there are at least 2,735 load or generation nodes in the RTO West system. If each node requires $50,000 for new metering, and the incremental capital costs are amortized over 25 years at 8 percent, the annual cost to consumers would be about $12 million.

d. New costs will be required for the services of a Paying Agent

The Stage 2 proposal includes retention of a Paying Agent. If the Paying Agent collects a fee of only $0.01/MWH on a total load in RTO West of 31,350 aMW (per TCA), the annual cost to consumers would be about $3 million.

e. Transactions costs will increase

Formation and start-up of RTO West will entail multiple filings at FERC and state regulatory commissions. Anecdotal evidence from California suggests new transactions costs due to the California ISO of as much as $0.60/MWH. Even if such costs are only one-quarter as large for RTO West, the annual transactions cost to consumers of RTO West would exceed $41 million.

f. Return-on-equity (ROE) will increase for investor-owned utilities who participate in RTO West

The Commission has discussed incentive rate-making in Order 2000. "To the extent consistent with ensuring that transmission rates are just, reasonable, and not unduly discriminatory, we believe transmission pricing disincentives to joining an RTO should be eliminated so that transmission-owning utilities will find RTO participation to be a dynamic business opportunity. <u>Utilities that join RTOs should be accorded transmission pricing that reflects the financial risks of turning facilities over to an RTO</u> and that reflects other changes in the structure of the industry." Order 2000 at 510 (emphasis added). In response to this invitation, many of the Filing Utilities have submitted an application to the Commission for approval of TransConnect, LLC, a for-profit independent transmission company (ITC). *See* Docket No. ER02-323-000. Three of the TransConnect filing utilities have specifically requested an increase in return-on-equity of 2.3 percent (230 basis points) on a weighted average basis. (See the testimony of James Piro on behalf of TransConnect (TC-2), comparing Period I and Period II *pro forma* returns-on-equity, and Exhibit 6 to this Protest.) The TransConnect utilities have also requested an "incentive" of 200 basis points on <u>new</u> transmission investments. (See the testimony of David Patton (TC-4 at 54) on behalf of TransConnect.) The TransConnect net book value is estimated to be $1.2 billion in 2004. (See the testimony of David Patton (TC-9) on behalf of TransConnect.) If the Commission approves a 230 basis point increase in return-on-equity as an incentive to all TransConnect shareholders to participate in RTO West, then TransConnect's consumers would pay an additional $28 million per year due to the formation of RTO West. This amount excludes the additional 200 basis point incentive that would be available for new transmission investments by TransConnect, and so is a conservative estimate of the additional costs to consumers.

g. New state and local taxes will likely be imposed on federal transmission assets, and possibly even generation assets, due to the transfer of control to RTO West

According to an independent analysis of the potential for new tax liabilities due to the shift in control of federal transmission assets to RTO West, there is a risk that consumers will pay approximately $141 million to $165 million in higher taxes, plus a one-time payment of approximately $300 million. *See* Exhibit 2 to this Protest. Adding the mid-point of this range and assuming that the lump-sum payment is spread over ten years yields an estimate of $183 million/year in additional costs due to RTO West.

This analysis yields a conservative (i.e., low) estimate of the potential tax liabilities for several reasons. First, it examined only Oregon and Washington tax law, so does not include the potential tax impacts of RTO West on federal transmission assets in other states. Second, the analysis does not attempt to analyze the extent to which RTO West might expose regional ratepayers to higher tribal taxes.[12] Third, it does not attempt to analyze the tax consequences of RTO West on the FERC-jurisdictional Filing Utilities or

[12] *See, e.g., Big Horn County Elec. Coop. v. Adams,* 219 F.3d 944 (9th Cir. 2000) (discussing tribal authority to tax transmission assets); Jeanne S. Whiting, "Tribal & State

on other aspects of the RTO West proposal that are likely to carry significant tax liabilities, such as the Scheduling Coordinator proposal. Fourth, this estimate is conservative because it includes only those federal transmission assets that are already in BPA's rate base or appear likely to be approved, and it does not include a number of the so-called "G-9" projects that BPA intends to build. Finally, this analysis does not address the potential for state and local taxes to be assessed on federal generation assets, which would also be placed under the control of RTO West pursuant to the TOA, at least for the purposes of providing Interconnected Operating Services (IOS), which would be resold by RTO West as ancillary services.[13]

The Filing Utilities have argued that several aspects of the Stage 2 proposal may prevent RTO West from incurring significant new tax liabilities.[14] A preliminary analysis of the Filing Utilities' response prepared by Northwest tax counsel concludes, however, that RTO West remains at substantial risk of incurring large state and local tax liabilities and that the structures incorporated into the Stage 2 proposal by the Filing Utilities may not be effective in preventing the imposition of state taxes. *See* Memorandum from Lane Powell Spears Lubersky re: RTO West Tax Analysis, May 24, 2002 (attached as Exhibit 8 to this Protest). For example, the Filing Utility analysis relies heavily on the argument that the use of a "Paying Agent" will prevent the revenues from the transmission services sold through RTO West from being attributed to RTO West for tax purposes. This arrangement

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Taxation of Natural Resources on Indian Reservations," Natural Resources & Env't, Spring 1993, at 17.

[13] *See* the Filing and Request for Declaratory Order at 47, n. 57 ("RTO West will have the authority to require those parties that wish to bid to provide Interconnected Operations Service to agree that the resources they bid will be subject to RTO West's direct or indirect operational control (for the period of delivery) if the bid is accepted.")

[14] *See* Filing Utilities' Response to Tax Analysis, May 21, 2002 (Exhibit 5 to this Protest).

may not succeed, however. Tax authorities look to the substance, not the form, of a transaction and could easily conclude that, despite the Paying Agent form, revenues from the sale of transmission access to the RTO West system are attributable to RTO West. Similarly, RTO West must assume operational control over the BPA transmission system to comply with Order No. 2000, and the degree of control required is likely to trigger state property and leasehold excise tax liability.

Finally, the entire tax liability issue arises because of the independence requirement in Order 2000: the more that federal assets (transmission or generation) are operated independently of BPA, the greater is the likelihood that state or local taxing authorities will be able to bypass federal tax immunity and levy taxes on federal assets. Hence, the risk of taxation of federal assets appears to be inherent in any attempt to comply with Order 2000. It is curious, therefore that the Filing Utility response of May 21, 2002 on these issues states that "RTO West will perform certain transmission functions for BPA as a government contractor." If so, then it would appear that RTO West will be a creature of BPA, not an independent entity. The Filing Utilities cannot have it both ways: either RTO West will be truly "independent", in which case federal assets are more likely to be taxed, or RTO West will not be truly independent, in which case RTO West will not be able to comply with the Commission's directives in Order 2000.

The TOA also includes a provision (§ 25.20.1) requiring RTO West to allocate the costs of taxes to the jurisdiction imposing such taxes. This provision must be rejected by the Commission for several reasons. First, it is contrary to long-established FERC policy calling for tax costs to be borne equally by all customers of jurisdictional entities.[15] The proposal is, in addition, inequitable to taxpayers in Washington state because, based on the results of the tax analysis referenced above, they would bear the bulk of the tax costs incurred by RTO West while the benefits of RTO West, if any, are likely to accrue broadly to all users of the transmission system. Indeed, in order to avoid this deleterious consequence, Washington would be forced to change its existing tax laws because the tax consequences of RTO West arise from the application of existing law.

In addition, the provisions of the TOA are vague at best: they require RTO West to allocate such taxes to two kinds of "loads". These "loads" are not defined in the TOA, which they must be because the "loads" in §25.20.1 should be a subset of other loads that are at issue in the TOA. It is possible likely that RTO West will not have any contractual relationship with such undefined loads, especially if the loads at issue have not converted pre-existing contract rights to some form of transmission service purchased from RTO West. In the absence of such a contractual relationship, RTO West may not have the information required to actually make such a targeted allocation of tax liabilities. In addition, the RTO West allocation process would target two kinds of loads: those "taking service from facilities located within a lawful taxing authority's boundaries", and those "taking transmission services from points of delivery on the Electric System of the Participating Transmission Owner whose transmission facilities are subject to such tax." The TOA does not specify that the second group of loads is in any way connected to (e.g., a subset of) the first group of loads, which means that RTO West could, as a practical matter,

[15] *E.g., New England Power Co.*, 8 FERC ¶ 61,054 (1979), *aff'd sub nom. NEPCO Municipal Rate Committee v. FERC*, 668 F.2d 1327 (D.C. Cir. 1981), *cert. denied,* 457 U.S. 1117 (1982); *Transcontinental Gas Pipeline Corp.*, 28 FERC ¶ 63,086 (1984).

actually allocate some state and local tax liabilities to loads outside the appropriate taxing authorities' boundaries. If so, it is likely that FERC would have to review and approve, and adjudicate disputes over, each such inter-jurisdictional transfer of state and local tax liabilities, both between local taxing authorities and between states. Such federal interference in local taxation issues, especially within a given state, is highly inappropriate. This provision is thus both unworkable and bad public policy.

h. RTO West will increase the risk of the exercise of market power

As is discussed further below, the Stage 2 congestion management proposal contains a clear danger of the exercise of market power. In the presence of concentrated markets, voluntary bidding, and subjective evaluations of forward opportunity costs, consumers could easily see rate increases in the hundreds of millions, or even billions, in one year, if the California experience is any guide.

i. RTO West will reduce reliability

As is discussed further below, the formation of RTO West is likely to reduce reliability. The congestion management market design is open to the kinds of market manipulation and "gaming" that may have also undermined reliability in California in 2000 and 2001. If so, then consumers will suffer from a higher probability of outages, at an unknown cost.

j. New liability insurance costs will be incurred

The Filing and Request for Declaratory Order notes a requirement for RTO West to purchase insurance (at 21). According to section 19 of the TOA, RTO West would be required to carry a general liability policy and a separate errors and omissions policy. There are no coverage amounts specified, but the TOA suggests that these two policies could have coverage limits in excess of $100 million each. Given the risks associated with a new institution such as RTO West, especially given the experience of 2000 and 2001, the insurance premiums associated with these liability policies could be substantial. Indeed, many of the utilities have used a similar argument to justify a request for higher returns-on-equity for another new entity: TransConnect. "The incentive-adjustment to the return on equity is a mechanism to ensure the [TransConnect] Applicants will have adequate incentives to undertake new investment projects and attract the necessary capital in light of <u>new risks facing the industry and independent transmission companies in particular</u>." (Testimony of David Patton, TC-4 at 38, emphasis added.) Despite the evidence presented in Docket ER02-323-000 in support of the need for higher risk-adjusted returns-on-equity, the Filing Utilities have elected to ignore this source of higher costs for consumers in the instant docket, and have provided no estimate of the costs that RTO West would incur and pass along to consumers associated with these new insurance policies.

k. New costs will be incurred associated with meeting creditworthiness standards

The Stage 2 filing includes a extensive discussion of the need to develop new creditworthiness policies and standards. *See* Filing Letter at 25-26, and Attachments J3, J5, and J6. Meeting these standards cannot be expected to be a free good. The Filing Utilities have provided no evidence on the costs to consumers of these new standards, but it would not be reasonable to assume that the costs are zero.

l. The total of these additional costs far outstrips any potential for benefits to consumers due to RTO West

The net result of these additional problems is an estimated net cost to consumers that could be as high as $450 million annually due to RTO West. (*See* Exhibit 6 to this

Protest). The information available at this time supports the conclusion that RTO West fails a fundamental test in the Federal Power Act.[16]

3. Additional Non-Quantifiable Costs of RTO West Show that RTO West Will Harm Consumers

Some of the non-quantifiable costs are potentially significant. These include the risk of decreased reliability, the economic consequences of the delay in construction of needed transmission reinforcements, and the exercise of market power. The problems of market power, the likely failure of the planning/expansion proposal, and the negative impacts on reliability are described in sections III, IV and VII of this Protest. In addition, the congestion management proposal identifies the "need to address uncertainties related to cash flow and contingencies", and suggests the need for a "congestion management reserve account." *See* Filing Letter, Attachment F at 11, footnote 11. (*See also* Attachment F at 16, where the uncertainty associated with "actual redispatch costs" is identified.) This reserve account is functionally a form of insurance against the new uncertainties associated with the operation of the congestion management system, and the premiums that consumers would have to pay, in effect, to RTO West for such insurance are a new cost that will drive up retail rates. It is insufficient to simply state that "RTO West would stand ready" to cover errors in estimated redispatch costs. (*See* Filing Letter, Attachment F at 16.) RTO West is proposed to be a non-profit corporation, which means that only its customers will "stand ready" to cover such errors. Given the novelty of this proposed system, it is

[16] *See also* Thomas M. Lenard, "RTOs, Market Power and the New Regulatory Agenda at the FERC," Progress on Point Release 9.4, February 2002, at 21 ("The costs [of RTOs] to the efficient operation of the transmission sector are substantial and the benefits, if any, are quite speculative").

reasonable to expect that such errors may be common, and that customers will pay higher rates to cover the associated costs.[17]

II. THE STAGE 2 PROPOSAL CREATES AN UNCONSTITUTIONAL DELEGATION OF GOVERNMENTAL AUTHORITY; FERC CANNOT APPROVE AN ILLEGAL AGRANGEMENT

The Protestants object to BPA's intent to enter into the proposed RTO West Transmission Operating Agreement ("TOA"). If BPA enters into the TOA, the TOA would force a wholesale transfer many of BPA's statutory obligations, duties and rights to RTO West and would limit BPA's discretion in exercising many of its statutory obligations. RTO West's bylaws also eliminate any oversight of the governmental functions that BPA transfers to RTO West. Consequently, if BPA enters in to the proposed TOA it would be entering into an illegal contract, which by law would be void. The Protestants acknowledge the Commission's determination in the RTO West Stage I that BPA's decision or ability to join RTO West is not subject to review by the Commission. The Protestants, however, believe the Commission cannot provide the Declaratory Order requested by the Filing Utilities where the execution of the proposed TOA by one of the Filing Utilities, BPA, will result in an illegal and void contract.

Further, this flaw is inherent in Order 2000 because BPA must, to comply with Order No. 2000's "bedrock" independence requirement, surrender control over its transmission system to a degree well beyond what it can do constitutionally. Alternatively, if BPA limits its delegation as required by the Constitution, RTO West cannot meet Order 2000's independence requirement.

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[17] It is also possible for RTO West to make errors in assessing the "additional value provided by the early lock-down election" of Cataloged Transmission Right Customers.

The Protestants acknowledge that the Commission's determination in the RTO West Stage I that BPA's decision or ability to join RTO West is not subject to review by the Commission. The issue raised here, however, is of Constitutional import and transcends a mere argument about interpretation of BPA's organic statutes.

A. RTO West Bylaws and BPA's Compliance with the Transmission Operating Agreement Would be Unconstitutional.

Several provisions in the proposed TOA would transfer statutory functions and inherently governmental functions from BPA to RTO West. The RTO West bylaws provide that RTO West will have the independent and exclusive authority to proposed the rates, terms and conditions of transmission services provided over facilities that it controls, including federally owned facilities. As discussed below, BPA's compliance with the provisions in the TOA and RTO West's bylaws would result in an unlawful delegation of statutory authority to a private entity.

Section 6.4 of the TOA provides that the RTO West shall have the exclusive right and obligation to provide transmission customers with all transmission services over the transmission facilities it controls. Section 6.4 further sets forth that participating transmission owners shall not enter into any transmission agreements after the commencement date for RTO West to provide transmission services on the transmission facilities RTO West controls. If BPA enters into the proposed TOA, BPA would be delegating to RTO West BPA's statutory rights and obligations in providing transmission services, which exceeds BPA's authority to delegate governmental functions. The delegation is not rescued by Section 6.4.4, in which BPA reserves the right to serve loads

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See Attachment F at 17, footnote 17. These errors are also a source of new insurance costs for customers.

within the Pacific Northwest or to meet the requirements of Section 9(i)(3) of the Northwest Power Act. BPA has broader statutory obligations that BPA would not be able to achieve with this reservation.

Additionally, Section 6.4 requires potential BPA transmission customers, who want to use BPA's system to obtain transmission rights from RTO West. They must satisfy RTO West's terms and conditions for service and must enter into contracts with RTO West to receive service across federally owned transmission lines. Those terms and conditions could be different from their rights under BPA's organic statutes and, possibly, preclude those customers from obtaining transmission services from BPA.

Section 6.6 of the TOA transfers to RTO West all control and operation of the control areas of the participating transmission owner, including BPA if its enters into the TOA. RTO West may unilaterally modify the thermal and other operating parameters established by the participating transmission owners, provided RTO West complies with a few minor standards in making those revisions. This section forces BPA to subordinate its operational authority over its control areas to RTO West.

Other subsections in Section provide that, if BPA signs the TOA, RTO West will have (i) exclusive control over the transmission tariff that applies to BPA facilities, (ii) exclusive rights execute all contracts for transmission service across BPA's lines, (iii) exclusive administration of scheduling functions, and (iv) right to implement market power and price mitigation programs and price controls for BPA to comply with applicable FERC orders.

BPA has many obligations that it must fulfill to comply with its organic statutes. Those statutes include the Bonneville Project Act of 1937, 16 U.S.C. § 832 *et seq.*, (Bonneville Project Act), Pacific Northwest Consumer Power Preference, 16 U.S.C. § 837 *et seq.*, (Northwest Preference Act), Federal Columbia River Transmission System Act, 16 U.S.C. § 838 *et seq.* (Transmission Act), and the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. § 839 *et seq.* (Northwest Power Act).

Many of these functions are regulatory in nature or are inherently governmental functions concerning the use of federal facilities. Under the Bonneville Project Act, BPA is obligated construct and operate federal transmission lines to encourage the widest possible use of energy and to prevent the monopolization thereof. 16 U.S.C. § 832a(b). The Bonneville Project Act also obligates BPA to give preference to consumer-owned utilities in the sale and disposition of power generated at federal facilities. 16 U.S.C. § 832e.

The Northwest Preference Act requires BPA to set transmission rates and to provide access across federal facilities if surplus capacity is available. 16 U.S.C. § 837e.

Under the Transmission Act, Congress directs BPA to operate the Federal Columbia River Transmission System and to construct improvements and additions to integrate federal and non-federal generation facilities, to provide serve to BPA's customers, to provide interregional transmission facilities, and to maintain the electrical stability and reliability of the federal system. 16 U.S.C. § 838b. The authorities and duties of the Administrator are subject only to the supervision and direction of the Secretary of Energy. 16 U.S.C. § 838(b). The Transmission Act also requires BPA to provide to all utilities on a fair and nondiscriminatory basis any excess capacity on the federal transmission system. 16 U.S.C. § 838d.

Through these statutes, Congress directs BPA to implement Congress's policies for marketing federal power, for developing federal power and transmission facilities, and for use of federal transmission facilities. In many respects these statutory functions are regulatory in nature or inherently governmental functions that obligate BPA to regulate its customers' use of federal power purchased from BPA and their use of federal transmission facilities. BPA cannot delegate these governmental authorities to private parties such as RTO West.

Federal delegation of governmental authorities to private parties to implement laws regarding regulation of their own trade or industry is unconstitutional. *A.L.A Schechter Poultry Corporation et al. v. United States*, 295 U.S. 495, 537, 55 S.Ct. 837, 846, 79, L.Ed. 1570 (1935) (The administration of Congressional delegation of the regulations by the trade associations and members of the industry was unconstitutional). *See also Carter v. Carter Coal Co.*, 298 U.S. 238, 311, 56 S.Ct.855, 873, 80 L.Ed. 1160 (1936) (A congressional delegation of legislative authority to private parties without appropriate guidelines is prohibited under the due process clause of the Fifth Amendment). Pursuant to these holdings, Congress, BPA or even FERC cannot delegate regulatory authority to private parties, whereby the private parties will be regulating other private parties or controlling decisions that resulting in the taking of property or money from one party and providing it to other private parties.

Federal agencies are permitted to delegate legislative authority to private entities provided that the federal agency retains final review authority and specific guidelines for the private entities to follow. *Gleave v. Graham*, 954. F.Supp 599, (W.D.N.Y. 1997) (Subdelegation of executive authority by a federal agency to private parties is not invalid as a matter of federal due process, provided such federal agency retains final reviewing authority). RTO West meets neither of these requirements.

The Filing Utilities proclaim in their Stage 2 Filing and Request for Declaratory Order Pursuant to Order 2000 (Request for Declaratory Order) that the RTO West decision making process would be independent of any market participant or class of participants. Also, RTO West will have independent and exclusive authority to propose rates, terms and conditions of transmission service over the facilities it controls, including BPA's. Request for Declaratory Order at 31. Consequently, BPA would not have any final or ultimate oversight over the RTO West decision making process, rates, terms and conditions regarding transmission serve over the facilities controlled by RTO West.

Additionally, as noted above, several sections of the TOA transfers final authority and exclusive control of the participants' transmission facilities, including BPA, to RTO West. The guidelines and retention of ultimate oversight necessary to avoid the unconstitutional delegation of governmental authority is absent. BPA cannot enter into the TOA or participate in RTO West under the proposed bylaws without violating the Constitution.

B. BPA Cannot Delegate by Contract Inherent Governmental Functions.

As a federal agency, BPA has many inherent governmental functions that arise out of the Bonneville Project Act, Northwest Preference Act, the Transmission Act, and the Northwest Power Act. The inherent governmental functions include the allocation of federal resources, the operation of federal facilities and the collection of charges.

The federal Policy Letter on Inherently Governmental Functions[18] (OMB Policy Letter) sets forth guidelines for federal agencies to determine actions that are inherently governmental functions, which federal agencies should not delegate by contract to private parties. Although the OMB Policy Letter likely does not have binding legal effect, it provides guidance that federal agencies should follow.

The Policy Letter defines inherently governmental functions as actions that require either the exercise of discretion in applying Governmental authority or the making of value judgements in making decisions for the Government. It describes inherently governmental functions as actions that involve the interpretation and execution of federal laws so as to (i) exert ultimate control over the use or disposition of federal property including in the collection, or disbursement of federal funds, (ii) determine and advance the federal governments economic or other interests by contract management and other means, and (iii) bind the United States to take or not take some action by contract or otherwise.

Additionally, the Policy Letter provides guidelines for agencies in regard to what functions can be contracted for with private parties:

> While inherently governmental functions necessarily involve the exercise of substantial discretion, not every exercise of discretion is evidence that such a function is involved. Rather the use of discretion must have the effect of committing the Federal Government to a course of action when two or more alternative course of action exist . . . A contract may thus be properly be awarded where the contractor does not have the authority to decide on the course of action to be pursued but is rather tasked to develop options to inform any agency decision maker, or to develop or expand decisions already made by Federal officials.[19]

The proposed TOA, however, requires BPA to transfer many of discretionary functions or prohibits BPA from exercising its statutory discretion.

[18] Office of Management and Budget, Executive Office of the President, Office of Federal Procurement Policy, *Policy Letter on Inherently Governmental Functions*, 57 FR 45096.

Control of Transmission Facilities. Section 6.1 requires parties to the TOA to transfer operational control of their transmission facilities to RTO West. Section 6.4 provides that RTO West will have the exclusive right to provide transmission customers all transmission services over BPA's transmission facilities. Pursuant to Section 6.6, RTO West will assume control over and operate BPA's control area. RTO West may modify BPA's thermal and other operating parameters for RTO controlled facilities. Section 6.7 provides that RTO West shall have exclusive right to execute all contracts for transmission services over BPA's transmission facilities.

Section 4(d) of the Transmission Act states that the "Secretary of Energy, acting by and through the [BPA] Administrator, shall operate and maintain the Federal transmission system within the Pacific Northwest . . . ". 16 U.S.C. § 838b. Pursuant to this provision, BPA Administrator is expressly operate and maintain the federal transmission facilities. Pursuant to guidelines in the OMB Policy Letter, this statutory provision has the characteristics of an inherent governmental function since BPA's implementation of that provision concerns the ultimate control over the use or disposition of federal property. The OMB Policy Letter indicates that BPA should not enter into the proposed TOA where BPA must turn over to RTO West the ultimate control and operation of the federal transmission system.

Interconnections, Upgrades and Maintenance. Section 5.1 gives RTO West authority to set interconnection standards that are different than BPA's standards. Section 5.3 set forth the standards that BPA must follow to permit new physical interconnections and BPA has no discretion to deviate from those standards.

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[19] *Id.*, at section 7.

Section 14.2 of the TOA provides that RTO West has the authority to arrange upgrades or expansion of the federal transmission facilities if RTO West determines they are needed. Section 14.3 requires BPA, as the executing transmission owner, to allow the installations and interconnections, to cooperate and to exercise its eminent domain authority when requested by RTO West. Section 15 requires BPA to grant RTO West with the ultimate authority for long-range planning of all BPA's transmission facilities under the control of RTO West.

Section 4(d) of the Transmission Act requires BPA to construct improvements, additions and replacement facilities, as the BPA Administrator determines, to integrate federal and non-federal generation projects, to provide service to BPA's customers, to provide interregional transmission facilities, or maintain the reliability of the Federal generation system.[20] These statutory provisions grant the BPA Administrator considerable discretion in determining when and what type of facilities BPA should construct to meet the listed needs.

The OMB Policy Letter suggests that these statutory obligations are inherent governmental functions since BPA decisions to improve or expand the federal transmission system involve the exercise of substantial discretion. BPA decisions under these statutory provisions would commit the federal government to a course of action over another available course. As indicated in the OMB Policy Letter, BPA cannot enter into a contract that allows the private contracting party to make decisions regarding the need and type of upgrades and system expansions.

The TOA, however, prohibits BPA from exercising its statutory discretion in determining when to make upgrades and expansions to the federal transmission system.

The TOA transfers BPA discretion in planning and constructing upgrades and expansions to RTO West. The contractual prohibitions and transfer of obligations basically eliminates BPA's discretion under Section 4(d) of the Transmission Act. The OMB Policy Letter suggests that BPA cannot enter into the proposed TOA with these limitations on BPA's statutory authority.

Contract Administration and Cost Allocation Decisions. Section 5.2 provides that RTO has authority to require generators to execute Generation Integration Agreements with RTO West so that they can interconnect with federal transmission facilities. Section 14.2 also that RTO West shall have the right to allocate the costs of upgrades or expansion of the federal system under the control of RTO West to BPA to the extent RTO West determines that BPA's interconnected loads benefit from the upgrades and expansions.

Section 10 of the Transmission Act requires the BPA Administrator to equitably allocate the costs of the federal transmission system between federal and non-federal entities using the federal transmission system.[21] The OMB Policy Letter indicates that the interpretation of laws regarding use of federal facilities and collection of funds is an inherently governmental function. Also, the authority to bind the United States to take or not take some action by contract is also an inherent governmental function. The OMB Policy Letter indicates, therefore, BPA should not enter into the proposed TOA that includes these provisions.

C. The Commission Cannot Approve an Illegal Arrangement

Pursuant to the Administrative Procedures Act, the Commission must make decisions that comply with the law. Protestants believe that the Commission's approval of

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[20] 16 U.S.C. § 838b.

the proposed RTO West bylaws and TOA, given BPA's express intent to comply with both of those instruments and the potential unconstitutional and statutory violations, would be contrary to law and would ignor fundamental legal issues that the Commission must address in its determination.

III. RTO WEST WILL HARM THE RELIABILITY OF THE NORTHWEST ELECTRICAL SYSTEM

A. The Commission Must Assess Likely Impacts on Reliability

The Commission must consider the effects RTO West will have on the reliability of the power transmission system in the West. In fact, it has been the Commission's "consistent policy [] to assure that the exercise of its rate-making and other jurisdictional responsibilities supports and facilitates the continued high degree of reliability that has existed in the U.S. Indeed, 'transmission system reliability is one of the principle issues sought to be addressed by the Commission's rule making on Regional Transmission Organizations.'" *Notice of Interim Procedures to Support Industry Reliability Efforts and Requests for Comments*, 91 F.E.R.C. 61, 189 (2000) (emphasis added) (citing Order 2000, 65 Fed. Reg. 809 (2000)). As the Commission noted in Order 2000, "[t]o the extent a public utility proposes to participate in an RTO, we will process that application pursuant to FPA, Sections 203, 205 and other sections as appropriate." Order 2000, 65 Fed. Reg. at 841. The Commission must consider reliability if a public utility transaction will potentially affect reliability. *See Edison Mission Energy*, 96 F.E.R.C. 61, 032 (2001); *City of Las Cruces, New Mexico v. El Paso Electric Company*, 87 F.E.R.C. 61, 220 (1999) ("The Commission must still consider reliability issues under [FPA] Section 202(b)

[21] 16 U.S.C. § 838h.

regardless of whether such issues may also be relevant to proceedings in other forums."). Therefore, the Commission must consider the effects on reliability of the Filing Utilities' Request in this docket.

B. The Evidence Demonstrates that RTO West Will Harm Reliability

During the development of the RTO West Stage Two proposal, BPA commissioned an independent study of the likely impacts of RTOs generally on the reliability of the power and transmission system. (*See* Exhibit 3 to this Protest, which is a copy of the report prepared by Schweitzer Engineering Laboratories for BPA, dated February 22, 2002). This report is described as a "risk assessment" of the potential effects of RTOs on reliability. Schweitzer evaluated 48 potential impacts of RTO formation on reliability.[22] The risk assessment attempted to rank both the likelihood and the magnitude of the positive and negative effects, giving each effect a value between +25 (most likely and greatest positive effect) and --25 (most likely and greatest negative effect). Of the 48 potential impacts, 36 were given negative scores by Schweitzer, indicating the risk that the RTO will reduce reliability. Of these 36, six were given the highest possible negative score: the RTO will not put capital where it does most good, will reduce security, and will be a new entity likely to experience start-up problems. These are not trivial problems. Five more effects were described as "neutral": having a value of zero. This left only seven of the 48 effects as positive, and the highest positive score was only +9. Thus, not only is the number of negative effects greater than the number of positive effects, there is a much higher likelihood of more serious negative effects, according to this analysis.

[22] Table 1 in the Schweitzer report lists 48 characteristics, but the numbering system in the report indicates 47 because line number 31 is duplicated.

In the category of risks inherent to RTOs, Schwietzer concludes that "[m]oving to a new top-level organization does involve transitional reliability risk, such as new systems, people, and training."[23] This conclusion is shared by the North American Electric Reliability Council:

> The transition period from the existing grid operating arrangements to thenew world of RTO-managed grids may create some negative system reliability impacts. New systems and organizational structures will need to be implemented over very aggressive time lines. Operational and reliability issues include intra-RTO congestion management procedures, transfer of security coordination responsibilities, consolidation of control areas, establishment of uniform switching procedures, etc. The scale of the responsibilities being transferred to these new organizations is unparalleled in the history of the industry. . . . It is essential that the pace of transfer of control from utilities to RTOs be managed to ensure that the reliability of the electric power systems in North America are [sic] maintained.[24]

In addition to these transitional problems, Schweitzer reports that "there are some ongoing risks, such as the information and physical security risks that are heightened" because of the centralization of these functions.[25] In addition, "expecting an RTO to solve the capital-attraction problems of today's industry would only delay the solution of this key issue in building, operating, and maintaining a reliable transmission system."[26] Finally, the centralization of functions in the RTO makes it a prime target for influence by financially or politically motivated forces.[27] Recent revelations demonstrating that Enron and other

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[23] *Id.* at 11.
[24] NERC Reliability Assessment 2001-2010, p. 23, October 16, 2001.
[25] Schweitzer Report at 11.
[26] *Id.*
[27] *Id.* at 10-11.

power marketers have abused the rules of the California ISO and PX only heighten this concern. Again, NERC and DOE have echoed these concerns.[28]

In other cases, Dr. Schweitzer identified risks to reliability arising from the Filing Utilities' proposal to consolidate the existing control area operators in the RTO West region into a single control area operator. He concludes that:

> if sole control lies with an RTO and its resident experts, the system as a wholecould lose the benefit of having regional experts and their close understanding of details inside regional systems. The loss of such knowledge and their vested interest in system operation would make the power system more fragile and therefore less reliable.[29]

Similarly, since a single control area operator would receive data from a vast area covering, "[t]he RTO operator could be overloaded by vast amounts of data from a much larger area and system."[30] The concentration of data in a single control area operator also presents a significant information security risk: "[i]nformation and control actions need to move around a region of 50 million people; thus, the RTO becomes a prime target of information operations, information warfare, hackers, disgruntled employees, frustrated customers,

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[28] NERC Reliability Assessment 2001-2010 Page 23, October 16, 2001. ("Will this large size [of RTOs envisioned by FERC] improve reliability, as has been assumed, or will local reliability needs be sacrificed to promote greater economic efficiency? Who will state regulators look to if local reliability is not being maintained and what authority will they have to correct the situation? These are questions without clear answers."). In addition, the Department of Energy's recently released National Transmission Grid Study similarly states that "[e]ffective operation of RTOs will be technically challenging. The tools and technologies originally developed to support centrally planned, vertically integrated operations are inadequate to manage reliability in competitive, region-wide electricity markets where power flows are driven by market participants whose behavior cannot be predicted using only traditional monitoring and dispatch concepts." DOE, "National Transmission Grid Study", May 2002 at 27.

[29] *Id.* at 8.

[30] *Id.* at 9.

etc." In short, the Filing Utilities appear to have ignored the advice of their own reliability experts in proposing a single control area for RTO West.

Finally, Dr. Schweitzer warned that the uncertainty associated with RTO formation will further delay essential investment in transmission assets: "There is no reason to expect that establishing an RTO will solve the problem of attracting capital for the new transmission we need right now. Anticipating that an RTO might help solve this problem may delay the real solutions."[31] Again NERC shares this concern: "[I]n the longer term, it is not clear how some RTOs will identify, execute, and pay for necessary transmission system reinforcements. . . . There is concern that the already slow pace of transmission reinforcement may stop altogether for a period while the new rules are developed."[32] As discussed below, at section VII, far from solving this problem, the Filing Utilities' planning and expansion proposal will only make this problem worse because many of the critical rules for planning and expansion are ambiguous, undefined, or missing.

The Schweitzer report could be interpreted as a discussion of difficulties that should be avoided in the formation of an RTO generally. Any fair reading of the Schweitzer report would have to conclude, however, that RTOs in general inherently contain certain risks to electric system reliability, and that the single control area model proposed by the Filing Utilities in particular poses risks to reliability. The Schweitzer recommendations, moreover, will not enhance reliability over what it otherwise be <u>without an RTO</u>, but instead appear to be necessary to <u>restore</u> reliability to <u>pre-RTO levels</u>. As noted elsewhere, the costs that would be incurred to avoid these detrimental effects on reliability have been omitted from the cost-benefit analysis.

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[31] *Id.* at 10.

Finally, it now appears that one of the causes of rolling blackouts in California may have been actions taken by marketers to increase profits by various withholding strategies.[33] See the memorandum by Christian Yoder and Stephen Hall (December 8, 2000 at 3), which the Commission has received in its investigations in Docket No. PA02-2-000. This experience points out the very real threat to reliability associated with what are euphemistically termed "market design errors", but which in reality are examples of the implicit grant, and the explicit exercise, of market power. The opportunities for economic and physical withholding by generators in the voluntary, subjective LMP system proposed for RTO West are obvious. If California has any lesson to offer, reliability will suffer as a result.

C. The Planning/Expansion Process Threatens Reliability

The Stage 2 proposal includes a provision that requires PTOs to obtain approval from RTO West for so-called "adequacy projects". (*See* Attachment I, at 10, n. 3). There are two obvious problems with this proposal. First, "adequacy" (and other important terms such as "market failure") remains undefined, which means that market participants, including PTOs, will have no idea when the RTO is likely to deny a proposed "adequacy" project. This uncertainty will interfere with decision-making. Second, the proposal adds a new layer of review before any project intended to assure reliable service can be built. The delays associated with review by RTO West will hamper reliable service.

D. The RTO West Stage 2 Proposal Does Not Address These Likely Negative Impacts on Reliability

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[32] NERC Reliability Assessment 2001-2010 Page 23, October 16, 2001.

[33] Jason Leopold, "Enron Linked to California Blackouts: Traders Said Manipulation Began Energy Crisis," CBS.marketwatch.com, May 16, 2002.

One of the requirements of Order 2000 is that an RTO address short-term reliability functions and actually improve reliability. Not only did the Filing Utilities elect not to file the Schweitzer Report with the Commission, they have not described how the RTO will ensure short-term reliability, or how it will meet the Commission's goal of improving reliability. Nowhere in the Stage 2 filing is there a discussion of the actions necessary to overcome the problems identified by Schweitzer. Nowhere in the Stage 2 filing is there a description of the effects of degraded reliability on consumers. Nowhere in the Stage 2 filing is there a description, let alone a quantification, of the additional costs that would be imposed on consumers either to maintain existing levels of reliability or to cope with lower reliability. The Stage 2 filing therefore fails to address one of the basic requirements of Order 2000, and RTO West cannot be approved by the Commission for that reason.

Although mitigation of these risks may be possible, additional costs would be incurred in order to achieve such mitigation. Either reliability will be degraded, which will cause costs to consumers in the form of lost production, wages, and profits, or additional costs will be incurred by RTO West to avoid degrading reliability, and these additional costs will be passed along to consumers. In either case, consumers will bear additional costs that have not yet been quantified, and which cannot be justified by the meager benefits possible from an RTO in the Northwest. Thus, it is safe to conclude that the costs of RTO West formation and operation have been understated.

IV. RTO WEST WILL UNLEASH MARKET POWER

Recent events have demonstrated that newly designed power markets are subject to potential manipulation, deceit, price escalation, fraud, and massive transfers of wealth and income from a broad swath of consumers to a handful of suppliers. Indeed, gaming and market manipulation have been a nearly universal feature of deregulated markets around the world.[34] The RTO West Stage 2 proposal offers yet another experiment in market design, incorporating many of the design flaws that plagued the West Coast in 2000-2001 but absolutely no safeguards against a repeat of the California debacle. In fact, the Stage 2 proposal would provide clear opportunities for the exercise of market power in markets that appear to be extremely concentrated. It would be highly unwise, as well as illegal, for the Commission to approve yet another risky experiment in "market design". Indeed, the costs of such market manipulation could easily and quickly wipe out any possible gains that might arise from RTO West: "[t]he cost to consumers of such [electric market] manipulations can be huge . . . far exceeding any price reductions which could possibly be achieved by [electric market] liberalization."[35]

The Commission has initiated several investigations into the operation of Western power markets in 2000 and 2001. Demands for refunds are widespread and growing with each new revelation of potentially fraudulent behavior on the part of some market participant. Under these circumstances, the Commission should at least defer all action on any request for approval of RTO West until its deliberations in Docket No. PA02-2-000 are complete, and new policies and regulations are developed that respond to the crisis of

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[34] *See, e.g.*, Janusz W. Bialek, "Gaming the Uniform-Price Spot Market – Quantitative Analysis," IEEE Trans. Power Systems, 17 December 2001 (draft accepted for publication); Will McNamara, "Investigation in Texas Examines Possible Manipulation and Flaws in State's Deregulation Model," Scientech IssueAlert (March 28, 2002); "Electricity's Shocking State," The Press (Christchurch, New Zealand), April 3, 2002 ("The New Zealand electricity market is dysfunctional and destructive. . . . If its problems are not quickly resolved, it will result in job losses, lost investment, and gross economic damage").
[35] Bialek, *supra* note 29, at 1.

2000-01. To do otherwise would be to risk subjecting the West Coast to a repeat of those disastrous conditions.

A. RTO West Markets Do Not Meet the Definition of "Competitive"

1. Evidence Suggests that RTO Markets Are Highly Concentrated

The study conducted by Tabors Caramanis for RTO West included an examination of the structure of markets within the RTO West area, called a "market concentration analysis". The study examined geographical markets defined by a "clustering" analysis of nodal prices, and product markets defined by three time periods within each of the 12 months. Within each geographical/product market, the Hirschman-Herfindahl Index (HHI) was calculated. This analysis is different from other approaches to market concentration that might be used, but is the only quantitative analysis of RTO West markets available at this time. It is reasonable to use this analysis as a first step in the analysis of the risk that RTO West will lead to the exercise of market power.

The results of this market structure analysis are clear: "[m]ost destination markets in the RTO West region have HHIs that indicate a high degree of market concentration." (See Exhibit 1 to this Protest at 68.) Some markets have HHIs that are consistently in excess of 5,000. (See Exhibit 1 to this Protest at 77, Figure 7.) These HHIs are indicative of concentrated markets that are very likely to behave in non-competitive manners. Non-competitive markets cannot deliver the promised benefits to consumers of the Federal Power Act.

2. The Risk of Anti-Competitive Behavior Has Been Ignored by RTO West and the Filing Utilities

Protestants have asked on several occasions for an analysis of the behavioral dimensions of the market power problem within RTO West, including tests of the assumption that all generators will bid marginal cost, rather than practicing profit-maximizing bidding behaviors such as economic or physical withholding. RTO West and the Filing Utilities have consistently declined to fund such analysis. Given the apparently highly concentrated nature of the RTO West, additional analysis of structural concentration and behavioral risks is required. Furthermore, before reaching any conclusions on the Stage 2 proposal, the Commission should wait for the outcome of continuing investigations into West Coast energy markets, and require that structural and behavioral safeguards be incorporated into any future filings by RTO West.

B. The Congestion Management Proposal Is Fatally Flawed Given the Risks of Market Power

Despite the evidence of highly concentrated markets, the Stage 2 congestion management proposal incorporates elements that will actually enhance the ability of sellers to exercise market power. These elements must be rejected as anti-competitive, especially in the context of the evidence suggesting highly concentrated markets within RTO West.

1. Voluntary Bidding Will Permit Economic and Physical Withholding

The Stage 2 congestion management proposal clearly states that participation in the RTO West "inc and dec" bidding process will be "entirely voluntary". See Attachment F to the Filing and Request for Declaratory Order at 1. Recent evidence demonstrates that the "inc/dec" market was abused in California, perhaps widely. See the results to date of the Commission's investigations in Docket No. PA02-2-000. Given the concentrated nature of generation control in the RTO West area, this means that the largest generation owners will be able to practice economic and physical withholding, driving wedges into the LMP system, and pushing up the cost of energy to consumers on the RTO West system. Economic and physical withholding can drive up LMPs in specific locations, thus creating value for those holding FTOs while simultaneously harming competitors and competition by increasing congestion costs on other paths.

For example, assume that a Scheduling Coordinator holds an FTO from A to B and can practice economic or physical withholding at B, thus driving up the LMP at B and the value of the FTO from A to B. Assume that the Scheduling Coordinator also schedules power from C to D but does not hold an FTO on the C-to-D path. If the C-to-D schedule creates congestion, the Scheduling Coordinator may disadvantage competitors who are trying to schedule on the same path, while protecting itself from the costs of the congestion on the C-to-D path by artificially inflating the value of the A-to-B price differential. Similar "games" are now known to have been played by some market participants in California, and yet the Stage 2 proposal contains no safeguards against such behavior. This deficiency is fatal.

2. Subjectively Determined Opportunity Costs Raise the Risk of Market Manipulation

The Stage 2 congestion management proposal relies on purely subjective evaluations of marginal costs. See the Filing Letter, Attachment F at 7, referring to "experience, discretion and informed judgment" exercised over "multiple planning horizons" while excluding "analytical techniques". This means that the RTO West market monitors will have no ability to judge the accuracy or reasonableness of the voluntary bids, because sellers will be able to claim superior "experience and informed judgment", and there will be no objective yardstick by which to distinguish "judgment" from "manipulation". This deficiency is fatal.

We strongly agree with the Filing Utilities' description of the unique aspects of the Pacific Northwest's system of coordinated, hydro-based generation and the need to preserve the advantages of that system.[36] We also agree that any reform must preserve the benefits of that system and must be tailored to recognize the unique aspects of the system. However, the Filing Utilities' attempt to force the square peg of the Northwest hydro-based system through the round hole required of locational marginal pricing creates insuperable problems, chief among them being the lack of meaningful checks on the potential for market power abuse.

3. The Congestion Management Proposal Has No Price Caps or Other Forms of Market Power Mitigation

In spite of the clear risk of market manipulation, the Stage 2 proposal contains no limits on voluntary bids in the LMP system. In fact, Powerex, a wholly-owned marketing subsidiary of the British Columbia Hydro and Power Authority (B.C. Hydro, which is a Filing Utility), has argued that there should be no bid caps on hydroelectric generation. (*See* Comments of Powerex Corp. on the Commission's Working Paper in Docket No. RM01-12-000, at 5). This position appears intended to assure that there are no limits on the exercise of market power by Powerex when marketing hydroelectric resources owned by or under contract to B.C. Hydro. B.C. Hydro is a signatory to the Stage 2 filing, so the Commission is presented with the specter of a PTO arguing against price caps in the face of evidence of concentrated markets. The beneficiary of this argument is easy to identify. The lack of price caps or other limits on market power is a fatal deficiency under the circumstances.

4. The Congestion Management Proposal Does Not Address the Ability of Large Market Participants to Harm Downstream Competitors

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[36] Filing and Request for Declaratory Order, Congestion Management Proposal, Attachment F at 5-8.

Although there are several sellers of hydroelectric energy in the Northwest, one peculiarity of the coordinated hydropower system is that some market participants, unlike in a thermally-based system, are able to effectively control the fuel suppliers of their downstream potential competitors. This characteristic ("fuel externalities") means that it is possible for upstream generators to release water (fuel) at times and in patterns that are disadvantageous to downstream generators. (Thermally-based systems are not normally characterized by such fuel externalities.) Despite coordination, this risk exists even without an RTO. However, the LMP system would change the incentive structure. If upstream generators are provided an additional competitive advantage by a poorly conceived LMP system, additional harm to downstream competitors will be possible, with potentially devastating financial consequences. The lack of recognition of the potentially anti-competitive effects of fuel externalities is a fatal deficiency in the Stage 2 congestion management proposal, which has no limits on physical withholding.

C. The Largest Sellers of Generation in the RTO West Area are Essentially Non-Jurisdictional

Under current statutes, the Commission does not have jurisdiction over the prices that BPA would bid into an LMP system. In addition, despite the fact that Powerex, the wholly-owned marketing subsidiary of B.C. Hydro, holds a FERC marketing license, the Commission does not have jurisdiction over the prices charged by B.C. Hydro, a foreign entity, to Powerex. That is, Powerex could act as a conduit for B.C. Hydro's market power, without risking its FERC license, simply by claiming that it is just passing through prices from B.C. Hydro. Despite its ostensible oversight, the Commission appears to be powerless to influence the energy prices that Powerex will charge. These jurisdictional limitations mean that the Commission cannot approve the LMP system proposed in the

Stage 2 filing, because the Commission does not have the authority to oversee the reasonableness of the resulting energy prices.

D. Other Elements of the RTO West Proposal Will Support the Exercise of Market Power

1. Secret Negotiations for the Conversion of Pre-Existing Transmission Contracts Will Harm Competition

The congestion management mechanism contains a curious detail that raises the specter that market power will be created and exercised in the process of converting pre-existing contracts to service under RTO West. The biggest problem with the conversion principles is the selective and secretive nature of the process. The conversion of pre-existing contracts is entirely voluntary for PTOs, who will be engaged in private negotiations with RTO West over the "special rules" in such conversions if they indicate a "willingness to establish a relationship with RTO West through a Scheduling Coordinator." (*See* Filing Letter, Attachment F at 16 and page 2 of Appendix B). The nature of this "willingness" is undefined, and thus subject to abuse.

If a PTO indicates the appropriate degree of "willingness", it can then go on to negotiate (i) one set of "special rules" for the conversion of some pre-existing transmission contracts to catalogued transmission rights (CTRs), to be implemented as CTRs; (ii) another set of "special rules" for the conversion of other transmission contracts from CTRs to Financial Transmission Options (FTOs); and finally (iii) yet another set of "special rules" for other pre-existing transmission contracts that remain wholly unconverted. Each one of these three options (including the privately negotiated "special rules") can be expected to carry different risks and rewards, including the ability, perhaps, to use the conversion process to disadvantage competitors and hinder the development of competitive markets. It is reasonable to expect that PTOs will select the package of limited conversion to CTRs, full conversion to FTOs, and non-conversion that provides the greatest financial advantage to the PTO, given the "special rules", rather than the package that provides the lowest rates to consumers or provides the greatest enhancement to the development of competitive markets. In addition, PTOs may conduct private negotiations among themselves, much as they did in the development of the Stage 2 filing, which could lead to bilateral arrangements in support of "special rules".

While this approach to flexibility in conversion has merits, the Stage 2 proposal permits the flexibility to be exercised in a manner that creates congestion and thus enhances the value of FTOs, without solving any real congestion problems. (This would clearly be a "design flaw".) In addition, given the transmission market shares held by PTOs, it is possible that the flexible approach to conversion will actually create market power in either generation or transmission markets. This concern is enhanced by the fact that only some holders of pre-existing contract rights will have a seat at the table during the conversion exercise, which increases the likelihood that the result of the exercise will be discriminatory among market participants and preferential to the interests of the merchant functions of the PTOs. As a result, the Commission would have to conduct a highly detailed review of the actual conversion process, to prevent the creation and abuse of transmission market power (e.g., attempts to tie up all the capacity on a constrained line) or generation market power (e.g., attempts to create the appearance of congestion).

2. Extension of Rollover Rights Will Harm Competition

The pricing proposal (Filing Letter, Attachment E1 as well as Exhibit H to Attachment A) proposes that some pre-existing transmission agreements can be automatically "rolled over" for the duration of the Company Rate Period. Aside from the fact that such an automatic rollover right violates the intent of the settlement agreement reached in the BPA TR-02/TX-02 dockets in 2001 (see section VIII below), the combination of the rollover right with the secretive, "special rules" provisions of the congestion management cataloging process means that some transmission contract holders may emerge with "super rights" that provide undue competitive advantages, while other transmission contract holders, who are not part of the secretive conversion process, will lose rollover rights because the RTO West tariff could eliminate such rights.

3. RTO West's Discretion to Depart from Established Credit Policy Will Harm Competition

The Filing Utilities are admittedly still working on creditworthiness policies. One of the issues in developing such policies is the ability of RTO West to depart from established policies "in appropriate circumstances, such as taking into account a Scheduling Coordinator's access to funds in addition to the Scheduling Coordinator's formal credit rating". See the Filing and Request for Declaratory Order at 26. The purpose of this option for "departure" is apparently to address the possibility that the largest Filing Utility, BPA, will not have a "formal credit rating" in the same sense as other Scheduling Coordinators, and thus may need to rely on its "access to funds" rather than meeting the formal requirements of RTO West's unsecured-credit access policy. The proposed solution, however, raises the concern that the market for Scheduling Coordinator services will be undermined by RTO West. That is, if RTO West departs from its established credit policy for BPA, to enable BPA to provide Scheduling Coordinator services, the result may be an undue competitive advantage for BPA in the market for Scheduling Coordinator services. This could occur because BPA could be expected to rely on its ability to shift costs internally (e.g., between its transmission and power functions), plus the existence of take-or-pay contracts for both power and transmission, to cross-subsidize its provision of Scheduling Coordinator services. Such cross-subsidies could easily undermine the development of competitive markets in such services.[37]

This is not an idle or speculative concern. During the development of the Stage 2 filing, representatives of Protestants met with BPA staff to begin discussion of the Scheduling Coordinator services that might be provided by BPA. During one of these meetings, BPA staff stated that any costs incurred by BPA in the course of doing business with RTO West, including losses associated with the provision of Scheduling Coordinator services that are not covered by secured credit instruments or cannot be passed on to those customers who purchase such services from BPA, could be recovered by "just raising rates". For example, if BPA's Scheduling Coordinator function incurred an energy imbalance cost that could not be passed on to the customer associated with the imbalance, for whatever reason, and if BPA had not complied with RTO West's unsecured-credit policy because RTO West had approved a "departure", BPA would simply raise some rate (power or transmission) to cover the cost. If so, then any departure by RTO West of "established credit policy" for BPA would permit BPA to cross-subsidize its provision of Scheduling Coordinator services and interfere with the development of competitive markets for such services.

E. The TOA Permits PTOs to Prohibit RTO West from Establishing a Market Power and Price Mitigation Program

[37] This raises a broader issue: whether PTOs should be permitted to offer Scheduling Coordinator services at all, given the risk of cross-subsidies.

The Stage 2 proposal fails to include any prospective measures to prevent the abuse of market power. Even worse, it leaves to the Filing Utilities the decision whether to even institute a process at RTO West that might lead to market power screens.

As a general matter, the reliance on *ex post facto* remedies for market power abuse violates Order No. 2000. One of the Commission's principle concerns in promulgating Order No. 2000 is that *ex post facto* remedies for market power abuse are slow, cumbersome, and often ineffective.[38] The difficulty of adequately remedying the abuse of market power that occurred in California demonstrates the wisdom of the Commission's preference for prospective prevention of market power abuse. The Stage 2 proposal not only fails to solve that problem by putting in place a system up front to prevent abuse of market power, but, worse, it places the decision of whether to create market power screens in the hands of the transmission owners.

Section 6.7.7 of the TOA sets out three conjunctive conditions that must be met before RTO West can establish a market power and price mitigation program. The third of these conditions is that a PTO that is subject to the market power screening test must ask RTO West to establish such a program: the fox, in effect, must invite the farmer into the henhouse, before the farmer can check on the chickens. This condition creates two kinds of problems. First, if no PTO subject to the test asks for the market power and price mitigation program, RTO West cannot establish such a program. This provision of the TOA in effect eviscerates the entire market monitoring plan in the Stage 2 filing, and would leave RTO West and the Commission with no alternative but to rely on ineffective

[38] *See, e.g.*, Order No. 2000, slip op. at 68 ("the cost and time required to pursue legal channels to prove discrimination will often provide an inadequate remedy because, among other things, the competition may have already been lost").

retrospective remedies. Silence alone can thwart this provision of the TOA, leaving RTO West with no ability to even set up a program to mitigate market power.

Second, it is not clear which PTOs are subject to the test in the first place. If B.C. Hydro, for example, is not subject to the market power screening test because of limits on the Commission's statutory authorities, then a significant owner of transmission in the RTO West area has exempted itself from any potential burden associated with even asking for a market power and price mitigation.

F. Current Commission Policy Limits Approvals of Market-Based Rates

1. The Commission Requires Evidence of Absence or Mitigation of Market Power

The Stage 2 congestion management proposal is essentially a request for approval of market-based rates, if only in concept. Recent decisions by the Commission show that the Commission's current policy is to grant such authority only in the presence of information regarding either the absence of market power or a Commission-approved market power mitigation program.[39]

In these orders, the Commission has established a two-part test: either the Supply Margin Assessment (SMA) methodology will be applied, or the RTO (or ISO) will have a Commission-approved market monitoring and mitigation plan. The purpose of this two-part test is to protect consumers from the exercise of market power.

2. No Evidence on Absence or Mitigation Has Been Submitted by the Filing Utilities

[39] See, for example, "ORDER AUTHORIZING TRANSFER OF ASSETS, GRANTING MARKET-BASED RATES AND ACCEPTING RELATED AGREEMENTS FOR FILING", 98 FERC ¶61,306, Cinergy Services, Inc. et al., Docket Nos. EC02-15-000, EC02-15-001, ER02-177-000, ER02-177-001, and ER02-177-002, March 18, 2002.

In the Stage 2 filing, neither condition in recent Commission orders has been fulfilled. First, the Filing Utilities have not provided any information that would assist the Commission in applying the SMA. The only evidence available regarding market structure is that the RTO markets are likely to be highly concentrated. Second, the Commission has not approved a market monitoring and mitigation plan. The only proposal before the Commission for market monitoring is much too modest and preliminary to qualify as a "market monitoring plan", and the TOA provides each jurisdictional PTO with the ability to stop the development of a plan. Rather, the Stage 2 filing is more of a "promise of a process". Many elements of the "plan" point to the need to "provide more specifics". Mitigation itself is limited to the options that are available to the Commission under current jurisdictional limitations, which may not be sufficient to address the exercise of market power. The Market Monitoring Unit (MMU) will also be hampered by an inability to compel the production of information. The entire data collection section of the "plan" is clearly described as a "placeholder", to be replaced once RTO West Markets "have been more fully defined". (See Filing Letter, Attachment H1, section F.1.) Critical elements such as the criteria by which market performance will be judged are missing (e.g., indices and screens). The proposed "plan" is clearly immature and unripe for Commission action. Thus, the second condition of the two-part test cannot be met.

G. The Commission Cannot Approve the Stage 2 Filing Without First Addressing the Need for Mitigation of Market Power

1. Recent Evidence Demonstrates that Redesigned Power Markets Are Subject to Manipulation

The Commission is currently conducting a detailed and intensive investigation (Docket No. PA02-2-000) into allegations that the West Coast energy crisis of 2000-2001 may have been exacerbated, or even caused, by manipulation of energy markets. Information that has recently come to light suggests that energy traders will take advantage of any deficiency in market design to artificially inflate prices to their own advantage, irrespective of the impacts on reliability, consumers or markets generally.

2. The RTO West congestion management proposal will create incentives for manipulation of markets

The RTO West Stage 2 proposal on congestion management is extremely vague, yet contains some fatal design flaws that would be subject to the same manipulation that plagued the West Coast in 2000 and 2001: voluntary bidding, no price caps, and no objective benchmarks for operating costs. If sellers do not have to bid, economic and physical withholding can be practiced. If there are no price caps, as Powerex has advocated, sellers will be free to practice economic and physical withholding using the sky as the limit on prices. If there is no objective benchmark for operating costs, because "experience and judgment" rule, there will be no means by which the RTO West market monitors (if they are even permitted to watch by the PTOs) will be able to determine whether any bid, for \$50/MWH, \$500/MWH, or \$5,000/MWH, is "just and reasonable". Without objective benchmarks, the Commission will not be able to determine that the resulting LMPs are "just and reasonable" under the Federal Power Act. Thus, market power is a fatal flaw in the Stage 2 proposal.

H. The Commission Must Not Approve the Stage 2 Congestion Management Filing

These problems add up to an indictment of one of the most fundamental components of the Stage 2 filing: the Potemkin village called "congestion management". The doors on the facades of this village are the trendy labels of deregulation that are too often applied without due consideration of the facts on the ground: "security-constrained least-cost redispatch", "marginal prices", "opportunity costs", "locational, bid-based prices", and "marginal costs". Putting the labels on the doors does not offset the fact that only cold and empty steppes lie behind those doors. The flaws in the congestion management proposal are fatal.

V. THE STAGE TWO FILING IS INCONSISTENT WITH THE COMMISSION's REQUIREMENTS AND EXPECTATIONS IN ORDER 2000

A. The Stage Two Filing Is Largely Incomplete

Despite the reportedly significant effort that went into developing the Stage 2 proposal, there are several critical elements that are missing from the March filing.[40] In the absence of these elements, the Commission cannot determine the compliance of the Stage 2 filing with either Order 2000 or broad Commission policy. Following is a list of the elements that have been recognized by the Filing Utilities themselves as missing from the Stage 2 proposal.

- The "unsecured-credit policy" is critical to understanding the risks that RTO West would assume, as well as the likelihood of preferential treatment of some Scheduling Coordinators at the expense of other Scheduling Coordinators and thus the development of competitive markets in these services. However, this policy is under continuing negotiations (*See* the Filing and Request for Declaratory Order at 25).

- The Generation-Integration Agreement (GIA) and Load Integration Agreement (LIA) are both missing. These are critical to understanding the obligations of both RTO West and Scheduling Coordinators who wish to do business directly with RTO West. The

[40] The level of effort that went into the Stage 2 filing is not completely known, because the meetings of the Filing Utilities throughout the process were not open.

ability to estimate the costs of Scheduling Coordinators will depend on a full understanding of both the LIA and the GIA.

- There is no definition of "Reference Year" in Exhibit A of the TOA, despite the fact that this term is used in the definition of "Transfer Charges". As a result, it is not possible to determine what the process is for determining Transfer Charge payments, which are critical components of the entire pricing proposal. Without clarity on Transfer Charge payments, it is possible that cost shifts will occur, thus violating Order 2000 and the Commission's Transmission Pricing Policy. It is also possible that the procedures for determining Transfer Charge payments will violate BPA's obligations to set rates under the Northwest Power Act.

- Exhibit C to the TOA is missing. This Exhibit is intended to provide a listing of all pre-existing transmission agreements. There is no ability to judge the viability of the Stage 2 proposal without a complete description of the set of agreements that the Filing Utilities expect to convert to RTO West service on a case-by-case basis. Because this selective conversion is itself a problem, there is a clear risk that the Filing Utilities will play "hide the ball".

- Exhibit E to the TOA is missing. It is not possible to judge the effects of the Stage 2 filing on reliability with the listing of the Critical Control Facilities.

- Exhibit F to the TOA is missing, and cannot be constructed by reference to Attachment F, which is only a Description of the Congestion Management Proposal. It is not possible to judge the effects of the Stage 2 filing on pre-existing contracts and the ability of RTO West to administer unconverted contracts without this information.

- Exhibit I to the TOA contains an "Example Draft" of External Interface Facilities. Without a definitive list, FERC cannot determine the impact of the pricing proposal.

- The Filing Utilities note that Exhibit K to the TOA will have to be refiled to conform to Stage 2, but has not yet been revised.

- Exhibit L to the TOA is missing. It is therefore difficult to estimate the costs of retaining a Paying Agent or whether, as the Filing Utilities assert, the Paying Agent structure will be effective in preventing the imposition of revenue-based taxes on RTO West.

- Exhibit M to the TOA is an "informational copy". It is not clear what that means. If Exhibit M changes, the ability of RTO West to comply with the Commission's expectations under Order 2000 regarding reliability may change. Any Commission decision on the Stage 2 filing would have to be revised.

- Exhibit O to the TOA is missing. There is no way to judge what effect this will have on markets and relations with Canadian transmission owners.

- Exhibit P to the TOA is "still being developed". Because the cataloging process would be subject to dispute resolution, the likelihood of cost shifts due to the formation of RTO West cannot be completely and accurately judged.

- There is no mechanism proposed for estimating and charging for the cost of transmission line losses. (*See* Filing Letter, Attachment E1 at 23). Because the amount and pattern of transmission line losses would be likely to change due to RTO West, a complete cost-benefit analysis requires a methodology for estimating and charging for line losses.

- The "specific market design and settlement system" is missing. (*See* Filing Letter, Attachment F at 2). Market design generally is critical given the obvious flaws in the design of California markets. The Commission should not approve a mere promise to do better.

- The scheduling rules have not yet been developed. (*See* Filing Letter, Attachment F at 2 and 10). The scheduling rules are critical elements in the market design, because they can create opportunities to "game" the system.

- The congestion management proposal lists several missing elements: ancillary services, scheduling and settlement processes, development of nodes and hubs, auction process, and operation of phase shifters and DC ties. (*See* Filing Letter, Attachment F at 23).

- Finally, many critical elements of the Stage 2 filing have been submitted in the form of discussion papers, which are basically promises to do more work. This limitation in the Stage 2 filing applies most critically to the proposals for pricing and congestion management, where the greatest risks of market manipulation lie.

Without these essential elements, the Commission is not in a position to judge the compliance of the Stage 2 filing with either Order 2000 or broad Commission policy, and it would be arbitrary and capricious to grant approval to the Stage 2 filing as submitted.

B. The Stage 2 Filing Does Not Meet the Commission's Requirements under Order 2000

In addition to the problems caused by missing elements, the information provided in the Stage 2 filing simply does not meet the detailed requirements in Order 2000 in many areas. In Order 2000, the Commission laid out four minimum characteristics and eight minimum functions of an RTO.[41] For each characteristic and function, Order 2000 provides some degree of detail regarding the Commission's expectations, and the Stage 2 filing can be held up against the collection of yardsticks in Order 2000, to determine if the Commission should grant approval as requested by the Filing Utilities.

1. The Filing Utility Response on Tax Liability Suggests that RTO West Will Not Be Independent

The Commission has previously approved the Stage 1 filing as complying with the independence criterion of Order 2000. *See* Order Granting, with Modification, RTO West Petition for Declaratory Order and Granting TransConnect Petition for Declaratory Order, Docket No. RT01-15-000 (April 26, 2001). As noted above, the Filing Utilities have recently released a Response to Snohomish Tax Analysis, dated May 21, 2002. See Exhibit 5 to this Protest. This analysis describes RTO West as a "government contractor". If this description is accurate, then RTO West will not meet the independence criterion of Order 2000. This new description of RTO West by the Filing Utilities requires the Commission to revisit the prior decision that RTO West fulfills the independence criterion of Order 2000.

[41] Protestants do not agree that Order 2000 provides a reliable policy roadmap to restructuring the electric power industry, especially in the Northwest. Thus, this section of the protest should not be interpreted as an endorsement of either Order 2000 in general or any of the specific details in Order 2000. However, the Filing Utilities have requested approval from the Commission under Order 2000, and as a result it is reasonable to inquire into the compliance of the Stage 2 filing with the requirements of Order 2000.

2. The Stage 2 Filing Does Not Fulfill the Operational Authority Characteristic (#3) of Order 2000

The operational authorities of RTO West are far from clear. In addition to the legal problems discussed above, there are technical reasons to reject the Stage 2 filing. Most prominently, the lack of a GIA in the Stage 2 filing means that the Commission cannot judge the likelihood that the short-term reliability characteristic will be fulfilled. In addition, the Filing Utility Response to Snohomish Tax Analysis states that "Bonneville employees would continue to operate the Bonneville system". (*See* Exhibit 5 to this Protest). This suggests that RTO West will not in fact have operational authority over federal transmission assets. There is no way at this time to evaluate the ability of RTO West to control, directly or indirectly, either transmission or generation resources.

3. The Stage 2 Filing Does Not Fulfill the Short-Term Reliability Characteristic (#4) of Order 2000

The Commission has stated that "the RTO should have full authority to order the redispatch of any generator" to maintain reliability. See Order 2000 at 318. The owners of federal generators in the Northwest (the Corps of Engineers and the Bureau of Reclamation) do not clearly have the authority to agree to submit to redispatch orders from a non-profit Washington corporation. Furthermore, portions of the capability of these federal resources have been sold under long-term contract to customers of BPA, and those contracts provide certain dispatch rights to the purchasers. It may be a violation of these long-term contracts to interpose RTO West into the contractual relationship.

4. The Stage 2 Filing Does Not Fulfill the Tariff Administration and Design Function (#1) of Order 2000

According to Order 2000, RTO West must have "sole authority" to make decisions on the provision of transmission service, including decisions on new interconnections. See

Order 2000 at 324. It would be unconstitutional and contrary to BPA's organic statutes for BPA to contract this responsibility to RTO West. Thus, RTO West cannot comply with Order 2000.

5. The Stage 2 Filing Does Not Fulfill the Congestion Management Function (#2) of Order 2000

The expectations of the Commission regarding congestion management in Order 2000 are extensive and detailed, but can be understood in terms of four fundamental criteria: "we believe that a workable market approach should establish clear and tradeable rights for transmission usage, promote efficient regional dispatch, support the emergence of secondary markets for transmission rights, and provide market participants with the opportunity to hedge locational differences in energy prices." See Order 2000 at 333. As is explained here, the Stage 2 proposal does not and cannot meet these four criteria, and therefore does not comply with the Commission's expectations in Order 2000.

a. The Stage 2 proposal does not establish clear and tradable rights for transmission usage

As submitted, the Stage 2 proposal holds merely a promise of establishing "clear and tradable transmission rights". The heart of this criterion is the definition of such rights in the first place. The congestion management proposal contains only a vague description of the process by which pre-existing rights will be catalogued or converted to RTO West service. The opportunities for the cataloging and conversion processes to break down or lead to preferential treatment are manifold. The "special rules" exception may be subject to manipulation by PTOs intent on protecting their merchant functions from competitive market forces (see Appendix B to the Stage 2 Congestion Management Proposal at 1). PTOs will hold a veto during the cataloguing process, subject to an undefined dispute resolution process that may or may not provide protections to holders of pre-existing contracts. The conversion of CTRs to FTOs requires the transmission customer to select a single diurnally-differentiated "feasible dispatch" of its generation, and subjects that dispatch to interpretation by RTO West to ensure that the resulting FTOs granted to the customer (i) have only "equivalent value" (equivalent to what?) and (ii) do not "increase the burden" on the PTO's Congestion Management Assets (compared with what?). These conditions are so vague as to be meaningless. As a result, there is no reasonable expectation that any pre-existing contract customer will elect to convert its CTRs to FTOs. Without conversion of CTRs to FTOs, the CTRs themselves remain untradable. (See Filing Letter, Attachment F at 4: "CTRs will not be tradable.") Thus, the congestion management proposal does not create tradable transmission rights.

The prohibition on trading CTRs is flawed for other reasons. To begin with, this provision violates existing contract rights to the extent those contracts allow the rights holder to trade unused transmission rights. In addition, the provision would likely to lead to phantom congestion since the holders of existing contracts would hesitate to convert those contracts to a new, untried, largely undefined and risky system of FTOs. It would be a flawed policy for the Commission to approve a proposal that does not allow unused CTRs to be traded, because that interferes with the development of liquidity in transmission markets.

b. The Stage 2 proposal will not promote efficient dispatch

As noted above, the geographical and product markets in RTO West appear to be highly concentrated. (See section IV of this Protest.) As a result of this concentration, combined with the ability of generators to practice economic and physical withholding due to the voluntary nature of the bidding process and the purely subjective nature of opportunity cost calculations, the RTO West LMPs are very likely to be driven by the exercise of market power, rather than marginal costs. Any price resulting from the exercise of market power will result in the efficient generation of power only by chance. Thus, it is not possible for the RTO West congestion management system to meet the Commission's "efficient dispatch" criterion.

c. The Stage 2 proposal will not support the emergence of secondary markets for transmission rights

Secondary markets clearly depend on (i) well-defined primary transmission rights that are (ii) tradable. As noted above, it is highly unlikely that primary transmission rights will be converted to FTOs, which is the only way that they will become tradable. Thus, the Stage 2 proposal will fail to support secondary markets in transmission rights.

d. The Stage 2 proposal will not provide market participants with opportunities to hedge locational energy price differences

According to the Filing Utilities, the RTO West LMPs will be based on "experience, discretion and informed judgment" applied over "multiple planning horizons", and not on "strictly analytical techniques". See Filing Letter, Attachment F at 7. The solution for dispatch in the proposed RTO West LMP system is "much more complex and uncertain" than in thermal-dominated systems that have "relatively consistent and predictable dispatch patterns." *Id.* Without some kind of "analytical technique", there is no reasonable prospect that market participants will be interested in providing hedging instruments for forward prices; in the alternative, suppliers of hedging instruments will command very high option premiums to cover the risks associated with the use of "experience, discretion and judgment" by generators in a position to exercise market power. LMPs will not be driven by "market fundamentals", which means that hedging costs will be unmanageable. As a result, market participants will not be able to rely on reasonably priced hedging instruments. The Stage 2 congestion management system fails to fulfill this criterion of the congestion management function.

The Commission should heed its own observation in Order 2000 that "LMP can be costly and difficult to implement, particularly by entities that have not previously operated as tight power pools." Order 2000 at 383. The RTO West Stage 2 congestion management proposal is testament to the wisdom of this observation. The Commission cannot find that the congestion management proposal meets the criteria of Order 2000.

6. The Stage 2 Filing Does Not Fulfill the Parallel Path Flow Function (#3) of Order 2000

The discussion of the parallel path flow function in the Stage 2 Filing and Request for Declaratory Order (at 44-46) points to the proposed congestion management model and the Western Market Vision, concluding that the combination provides "strong, effective tools" to manage parallel paths. There are two obvious defects in this conclusion. First, the congestion management proposal will fail, as discussed immediately above. Second, the Western Market Vision is just that: a "vision". It is not a program that contains sufficient detail for the Commission to conclude that it will meet the criteria of Order 2000. As a result, the Commission cannot conclude that RTO West will meet this condition.

7. The Stage 2 Filing Does Not Fulfill the Ancillary Services Function (#4) of Order 2000

Order 2000 requires several conditions to be met regarding the ancillary services function. Among other requirements, Order 2000 requires that RTO West have "direct or indirect operational control" over generators that provide ancillary services. As discussed above, federally-owned generation cannot be placed under "direct or indirect operational control" of RTO West. As a result, RTO West will fail to meet the Commission's requirements in Order 2000 regarding ancillary services. In addition, the existence of market power may interfere with the development of competitive ancillary services markets, which would also violate the spirit of Order 2000.

8. The Stage 2 Filing Does Not Fulfill the OASIS/TTC/ATC Function (#5) of Order 2000

Order 2000 (at 432) requires that RTO West operate at "Level 3" for ATC/TTC calculations. Level 3 requires that the RTO will calculate ATC values based on data developed partially or totally by the RTO. Offers of ATC would then be made by RTO West. As discussed above, non-federal entities cannot offer to sell capacity on federal transmission lines. The Commission cannot approve a contract that would violate the law. As a result, the Stage 2 proposal fails to meet the criteria of this function in Order 2000.

9. The Stage 2 Filing Does Not Fulfill the Market Monitoring Function (#6) of Order 2000

In Order 2000 (at 461-466), the Commission set out several elements of a market monitoring plan. These include examining the structure of the market and the behavior of market participants, and clearly identifying proposed sanctions or penalties. *Id.* at 464. The ability of RTO West to implement these elements would be undermined by the exception inserted by BPA into the Filing and Request for Declaratory Order (at 12, note 8), which cites the limited authority of the Commission over BPA's power rates. It is not clear how RTO West could actually impose sanctions or penalties on BPA, given existing laws. Even if sanctions or penalties were imposed by RTO West, BPA would simply pass these along in higher rates charged to its power and transmission customers. There is no meaningful way for RTO West to meet the criteria in this function.

10. The Stage 2 Filing Does Not Fulfill the Planning and Expansion Function (#7) of Order 2000

The planning and expansion objectives of Order 2000 include the encouragement of "market-motivated . . . investment actions" (at 485) and the assurance that the planning and expansion decisions "produce efficient outcomes" (at 489). As is discussed below in greater detail, the cost allocation provisions in the planning and expansion protocol will encourage market participants to socialize congestion costs. As discussed above, the congestion management system is itself fatally flawed and subject to the exercise of market power. These flaws will infect the planning and expansion mechanism. Thus, the Stage 2 planning and expansion proposal will fail both to encourage market-motivated investments and to yield efficient outcomes.

11. The Stage 2 Filing Does Not Fulfill the Interregional Coordination Function (#8) of Order 2000

As discussed above, the interregional coordination effort is aimed at further development of a Western Market Vision. There is insufficient information at this point to conclude that the Stage 2 filing will meet the criteria for this function.

C. The Stage 2 Filing Was Developed in a Manner that Is Inconsistent with the Public Process Expectations of Order 2000

The Commission identified the collaborative process as a "key element" of Order No. 2000 aimed at reaching "mutual agreement on how best to establish RTOs" in each region of the country.[42] The collaborative process was intended to include "public utilities and non-public utilities, in coordination with state officials, Commission staff, and all affected interest groups, will actively work toward the voluntary development of RTOs." See Order 2000 at 6.

[42] Order No. 2000, slip op. at 648.

The Commission should be under no illusion that the RTO West Stage 2 proposal was the result of a collaborative process. It was instead primarily the result of closed negotiations among the Filing Utilities with minimal input from other stakeholders. In fact, prior to the Stage 2 filing, stakeholders outside the Filing Utilities had never seen key elements of the Stage 2 proposal. Nor should the Commission be under the illusion that the Stage 2 proposal represents "mutual agreement" by the stakeholders in the Pacific Northwest. On the contrary, the Protestants strongly object to the Stage 2 filing on a number of grounds. Since the stakeholders other than the Filing Utilities have been largely excluded from the process of developing RTO West since December 2001, we have been left with little choice but to oppose RTO West in every available forum.

Since December 2001, the "collaborative process" has consisted of an unknown number of unannounced, unpublicized, and closed meetings of the Filing Utilities, punctuated by a limited number (three, to be exact) of opportunities for "all affected interest groups" to provide comments on the work products developed in private by the Filing Utilities. Compromises may have been developed during the private negotiations of the Filing Utilities, the full extent of which is yet to be revealed. The Stage 2 filing was not developed within either the letter or the spirit of Order 2000. The Commission may not approve the Stage 2 filing because it violates the collaborative process requirement, which the Commission has identified as a key element of Order 2000.

D. The Stage 2 Filing Contains Caveats and Other Uncertainties that Undermine the Compliance with Order 2000

In addition to the limitations and omissions noted above, there are several places in the Stage 2 Filing and Request for Declaratory Order where reservations of some of the

Filing Utilities are noted, which collectively suggest that the Stage 2 filing is not a "real proposal". For example:

- Avista and others have reserved the right to "not proceed" if limitations on liability are not adopted; see footnote 11, p. 15;

- NorthWestern's participation is uncertain because the cost-benefit study shows net costs for Montana; see footnote 12, p. 15;

- Utility restructuring between the Stage 2 filing and execution of the TOA could lead to the avoidance of obligations under the TOA; see footnote 17, p. 19; this suggests that the TOA is not a commitment;

- Avista and PGE have concerns about the backstop planning authority; see footnote 61, p. 53;

- PGE, Nevada Power, and Sierra Pacific did not sign the December 1, 2001 filing with the Western Market Vision; see footnote 65, p. 56; in light of this, it is not clear whether the interregional coordination function is supported by all of the Filing Utilities;

- BPA has reserved the right to negotiate modifications to the TOA if necessary to secure "an adequate appellate route"; see p. 62; this would seem to make the TOA only really a draft proposal at this time.

VI. THE RTO WEST STAGE TWO FILING IS INCONSISTENT WITH THE COMMISSION'S TRANSMISSION PRICING POLICIES AND IS OTHERWISE INTERNALLY INCONSISTENT

A. The Stage Two Pricing Proposal Is Inconsistent with Order 2000

Given the nature of the Stage 2 pricing proposal, it appears that Rube Goldberg has been resurrected and retained by RTO West to help design the recovery of embedded transmission costs. The complexity of the pricing proposal is clearly driven by the multiple objectives that constrain the development of RTO West. However, in Order 2000, the Commission set out two criteria for transmission ratemaking by RTOs, which require discussion: a prohibition on "rate pancaking" and a concern about "cost shifts": "the Commission is very concerned about potential impacts of market restructuring on the customers in 'low-cost' states, and the Commission therefore intends to monitor the effects of RTO formation on such customers, specifically the potential for cost-shifting effects of RTO pricing proposals." Order 2000 at 510; see also at 523. These criteria are addressed in turn.

1. Rate pancaking

On this issue the Commission is clear: "the RTO tariff must not result in transmission customers paying multiple access charges to recover capital costs." Order 2000 at 516. Despite this admonition, the Stage 2 pricing proposal contains several examples of "multiple charges" that will recover capital costs. The External Interface Access Fee (EIAF), allocation of Replacement Revenue Pool amounts, and the TOA Costs in their current configurations are all forms of rate pancakes: separate charges for the recovery of capital costs. They appear to be prohibited by Order 2000.

2. The pricing proposal will result in cost shifts and violations of law

One of the more complex elements of the pricing proposal is the External Interface Access Fee (EIAF), combined with the backstop revenue recovery mechanism, which is designed to help avoid cost shifts. Filing Letter, Attachment E1. Unfortunately, this is another house of cards. The TCA Final Study suggests that the formation and operation of RTO West will lead to a decrease in energy imports into the RTO West area, but no increase in energy exports. This means that there is no reasonable expectation of <u>any</u> EIAF revenues. The result is an estimated $127 million shortfall in transmission revenues. Filing Letter, Attachment E2 at 3, cell N17. This means that the pricing proposal will cause a $127 million cost shift immediately, and require BPA to charge its transmission customers for the costs of the transmission systems of regional investor-owned utilities.

<u>B. The Stage 2 Pricing Proposal Violates Commission Policy on Future Test Periods</u>

One other long-standing Commission policy regarding transmission rates would be violated if the Stage 2 pricing proposal were implemented. The pricing proposal includes a two-year test forward test period. See Filing Letter, Attachment E1 at 17. This is a violation of 18 CFR §35.13(d)(3)(ii), which defines Period II as a twelve-month period. In order to accept the RTO West Stage 2 filing, the Commission would need to revise its regulations.[43]

<u>C. The TOA Is Internally Inconsistent Regarding Pricing</u>

Section 17.1 of the TOA expressly prohibits RTO West from charging any PTO for profits or returns on the assets of another PTO. (*See* Exhibit 5 to this Protest. Exhibit I to the TOA creates a Revenue Recovery Target equal to the sum of non-firm and short-term revenues collected by PTOs in a Reference Period). If the revenues received by RTO West from the External Interface Access Fee are less than the Revenue Recovery Target, RTO West will allocate the undercollection to some or all PTOs. This allocated undercollection

will recover "profits or returns on the assets" of PTOs, to the extent that the historical non-firm and short-term revenues included such profits or returns. Thus, the prohibition in section 17.1 is in direct conflict with Exhibit I to the TOA.

VII. THE RTO WEST STAGE TWO PLANNING PROPOSAL WILL INTERFERE WITH TRANSMISSION EXPANSION

One of the critical criteria for judging the likely effects of RTOs is their ability to support or interfere with expansion of the transmission system where needed. In this regard, the Stage 2 proposal fails spectacularly, because it creates a procedural opportunity for market participants to use RTO West to avoid paying congestion costs and instead shift them to others through a subterfuge in the planning process. This opportunity means that congestion costs will be socialized, which is also a violation of the Commission's current policies. "Market designs that base prices on the averaging or socialization of costs, may distort consumption, production, and investment decisions and ultimately lead to economically inefficient outcomes. Where possible and cost effective, cost causality principles can be used to price services and eliminate averaging." (*See* Order 2000 at 642 (footnotes omitted)).

The Planning and Expansion Proposal provides that any "project sponsor" can request that RTO West allocate the costs of an upgrade or new facility when the sponsor can "demonstrate that its project confers a needed transmission adequacy benefit on a PTO(s)." In turn, "transmission adequacy benefit" is defined as the deferral or avoidance of a "transmission adequacy solution" within the RTO's planning horizon. See Filing Letter, Attachment I at 14. Because the RTO's planning horizon can be expected to be

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[43] The Stage 2 filing is also inconsistent with the proposal by the TransConnect utilities to

lengthy, any market participant can claim at any time that any project will confer a "transmission adequacy benefit". Thus, there is no limit on the ability of any project sponsor to request a cost allocation for an upgrade or new facility from the RTO. Market participants who want to avoid the cost of either buying FTOs or of actual, day-to-day congestion will have an incentive, and an opportunity, to propose a project to the RTO and claim a "transmission adequacy benefit". The RTO would then allocate the costs of the upgrade to various market participants, including entities that have already purchased FTOs or who have decided to bear the risk of day-to-day costs of congestion. These allocated upgrade costs, which are actually avoided congestion costs, would be effectively socialized by the RTO, thus violating Order 2000.

VIII. THE STAGE 2 PROPOSAL FAILS TO FULLY HONOR EXISTING TRANSMISSION AGREEMENTS, INCLUDING SETTLEMENT AGREEMENTS IN BPA TRANSMISSION RATE AND TARIFF CASES

A. Under Recent Commission Precedent, Existing Contracts Must Be Honored Absent Extraordinary Circumstances Not Present Here

In Protestants' view, one of the fundamental conditions required of any RTO is that it fully honor existing transmission contract rights. Indeed, the Commission has recently set an extraordinarily high bar to clear before existing contracts can be abrogated:

> The Commission's long-standing policy . . . has been to recognize the sanctity of contracts. Rarely has the Commission deviated from that policy, and then only in extraordinary circumstances. . . . Preservation of contracts has, if anything, become even more critical since the policy was first adopted.[44]

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rely on a standard Period II analysis.

[44] *Nevada Power Co. v. Duke Energy Marketing & Trading LLC,* 99 FERC par. 61,047, slip op. at 12 (April 11, 2002); *accord Public Utils. Comm'n of California v. Sellers of Long Term Contracts,* FERC Docket No. EL02-60-000 (April 25, 2002).

That statement was made, moreover, in the context of the wholesale power crisis growing out of California's botched experiment in electric deregulation, a situation the Commission has already concluded produced a dysfunctional market. The transmission contracts at issue here, by contrast, contain no taint of market dysfunction, exercise of market power, or other indicia of monopoly abuse that would justify abrogation or modification of those contracts under the extremely high bar set by the Commission. On the contrary, they were entered into by Protestants primarily in order to provide reliable and economic service to end-use electric consumers and the contracts have generally functioned well in achieving that end. Accordingly, the Commission cannot, consistent with recently-established precedent, endorse an RTO that abrogates or modifies contract rights under existing contracts. Furthermore, it would be arbitrary and capricious for the Commission to do so.

The Stage 2 proposal ostensibly honors existing contract rights by allowing customers taking service under existing contracts to continue to take such service. However, the proposal contains a number of restrictions and limitations that either modify existing transmission contract rights or else impose significant procedural limitations on the ability of existing contract rights holders to protect their existing contract rights.

<u>B. BPA and Its Customers Reached a Settlement Agreement in 2000 Regarding Rollover Rights</u>

In 2000, BPA conducted a parallel set of processes under Section 7 of the Northwest Power Act and Section 212 of the Energy Policy Act, to establish rates, terms, and conditions for transmission service of general applicability. *See* Commission Orders of May 7, 2001, and October 1, 2001, Docket No. EF01-2021-000. During these processes, settlement agreements were reached in April and June 2000 on various issues. These settlement agreements were filed with the Commission as part of the administrative record in these dockets. Most if not all of the Filing Utilities, including BPA, were signatories to these settlement agreements in these dockets, as were many of the Protestants in this RTO West docket number. Several aspects of the settlement agreement regarding the terms and conditions of service addressed the transition from BPA's previous open-access transmission tariff (OATT) to the new OATT that became effective on October 1, 2001.

<u>C. The Intent of the Settlement Agreement Was Clearly to Limit the Scope of Rollover Rights in the Case of Some Transmission Contracts</u>

During the settlement negotiations, a general concern surfaced that some holders of pre-existing contract rights would use the indefinite rollover rights in BPA's new OATT to "lock up" transmission capacity using techniques that were unavailable under BPA's previous OATT. As a consequence, section 3 of the June 2000 settlement agreement explicitly addressed various types of rollover rights; section 3.2 specifically limited certain kinds of rollover rights:

> For Transmission Customers with advance reservations with a Service Commencement Date on or after October 1, 2001 that were requested prior to April 20, 2000, section 2.2 rights will be limited to three (3) consecutive rollovers of one (1) year each following the termination of the current Service Agreement. This paragraph does not apply to contracts or converted contracts referred to under section 3.1 above.

The clear intent of the parties to this settlement agreement was to <u>limit</u> rollover rights in certain (but not all) instances. For the category of Transmission Customers meeting this definition, rollover rights would be extinguished no later than three years after the termination of the underlying Service Agreement. For the Protestants, this represented a trade-off: when the rollover rights terminate, the associated transmission capacity would be freed up for another use (by any Eligible Customer or subject to other rollover rights) but the associated transmission revenues would be lost, which could theoretically cause upward pressure on BPA's transmission rates. However, due consideration of the value of this tradeoff led to the agreement to limit rollover rights.

The set of transmission contracts that met the conditions of the settlement agreement was known in June 2000, because requests to use BPA's transmission system were posted on the BPA OASIS. For example, one of these transmission contracts was issued pursuant to Request No. 85, submitted to BPA on March 17, 1999 by Powerex, the marketing affiliate of one of the Filing Utilities: B.C. Hydro. Powerex had obtained 300-400 MW of rights on the D.C. Intertie connecting Big Eddy to the Nevada-Oregon Border (NOB), on a seasonally-shaped, long-term basis: the rights were concentrated in the summer months. See Exhibit 7 to this Protest. These rights would have terminated on September 1, 2003 absent the settlement agreement, but could be extended by Powerex until September 1, 2006 under the settlement agreement.

D. The Stage 2 Proposal Creates an Automatic, Long-Term Extension of Rollover Rights That Is Different from the Intent of the Settlement Agreement

The Stage 2 pricing proposal specifically addresses and creates new types of rollover rights. Exhibit H to the TOA (at H-1 to H-2) provides as follows:

> If the Executing Transmission Owner has a Pre-Existing Transmission Agreement with another Participating Transmission Owner that (1) is necessary to meet its own load service obligations within RTO West, (2) expires during the Company Rate period and (3) provides for rollover rights, pursuant to the agreement or the Participating Transmission Owner's Open Access Transmission Tariff, then upon expiration of the agreement, the agreement shall be automatically extended through the remaining term of the Company Rate Period, and the Executing Transmission Owner shall (i) continue to receive service pursuant to the agreement, and (ii) pay the Participating Transmission Owner's applicable contract charge for non-converted pre-existing open access transmission tariff agreements. This provision will not apply if and when the Executing

> Transmission Owner no longer needs the service under the agreement to meet its own load service obligations within RTO West.

This provision would override the understanding reached in the June 2000 settlement agreement, by establishing a rollover right that would last for the duration of the Company Rate Period. The Company Rate Period is currently proposed to run for eight years after the Transmission Service Commencement Date of RTO West; according to the "illustrative implementation plan", the Transmission Service Commencement Date is estimated to be January 2006. See Filing Letter, Attachment L at 5. Thus, the new, long-term rollover right created by the TOA would run through December 2013, or <u>more than seven years beyond the limit on rollover rights set in the settlement agreement</u>, in the case of the Powerex contract.

It may be argued that the three-part test in the definition of the new rollover rights itself will serve to limit its application. However, the first part of the test is fatally vague: "need", like beauty, lies in the eye of the beholder, and the rollover right is "automatic". Is "need" associated with the physical delivery of power, or the economic interests of the Executing Transmission Owner? In either case, "need" would appear to be trumped by the "automatic" nature of the rollover right.

<u>E. BPA and the Filing Utilities Have Violated the Intent of the Settlement Agreement and Have Created the Potential for Preferential Treatment</u>

This new rollover right clearly is contrary to the intentions of the parties in June 2000 when the settlement agreement was negotiated. Even though the term of that settlement agreement was limited to the period October 1, 2001 through September 30, 2003, the express inclusion of language in section 3.3 limiting certain rollover rights to three years is clear evidence of the intent of <u>all</u> the parties to extend the reach of the settlement agreement beyond September 30, 2003. Had that not been the intent, or had the parties wanted to avoid addressing the extent of rollover rights, no language addressing such limitations would have been necessary. By including in the Stage 2 proposal new rollover rights that can be extended "automatically" at the option of the transmission customer through 2013, the Filing Utilities have violated the intent of the June 2000 settlement agreement.

Finally, the new, automatic, long-term rollover right is limited to transmission owners that execute the TOA, which is preferential and discriminatory. One of the main beneficiaries of this provision would be Powerex, the marketing affiliate of one of the Filing Utilities, who would gain an additional seven years of seasonally shaped transmission rights on the D.C. portion of the Pacific Intertie. This form of seasonally shaped, long-term service is no longer offered by BPA, so this automatic extension of the rollover right would provide Powerex a long-term competitive advantage, based on its affiliation with one of the Filing Utilities. Transmission contract holders who do not sign the TOA do not receive the new, automatic, long-term rollover right. The effect is discriminatory and preferential, to the benefit of PTOs but not other market participants.

F. The Stage 2 Proposal Restricts the Rights of Contract Holders in the Cataloguing Process, Thus Making It Impossible To Ensure That Contract Rights Can Be Fulfilled

The Stage 2 proposal excludes contract rights holders from the cataloguing process, which compromises the ability of those rights holders to ensure that the physical capacity is available to fulfill their rights. Cataloguing is left instead to the PTO and RTO West, both of whom have an incentive to restrict the amount of assets provided in the catalogue. The TOA provides that RTO West will provide transmission rights to each PTO sufficient to meet the PTO's contractual obligations to its existing customers. See Filing Letter, Attachment A, §§8.3, 9.2, 9.4. RTO West catalogues those existing transmission rights. Cf. Filing Letter, Attachment A, §8.3. The rights to have existing transmission rights catalogued and the rights to have those existing rights served, however, are rights and obligations of RTO West and the PTO. To the extent that there is a dispute over the cataloguing process, the rights holder, who is the party most directly affected by the cataloguing decision, is excluded from the arbitration.[45]

The existing rights holder must receive all of the rights to which it is legally entitled pursuant to the underlying contract. Yet, under the Stage 2 proposal, the existing rights holder is not permitted to participate in either the cataloguing process or in any dispute resolution process arising out of cataloguing. The Stage 2 proposal therefore seriously compromises the ability of existing rights holders to vindicate and protect their contract rights in the RTO West system.[46] The Commission cannot approve a proposal that excludes existing contract rights holders from the cataloguing process and from any dispute arising from the cataloguing process that implicates its contract rights.

Similarly, to the extent an existing contract rights holder elects to convert its contract to catalogued transmission rights, the rights holder would be excluded from both the process of cataloguing and any dispute arising from the cataloguing process. See TOA §9.3.2. Not only does this arrangement seriously compromise the ability of holders of existing rights to ensure that their rights are fully honored in the conversion process, it also

[45] The dispute resolution procedures in Exhibit P of the TOA are available only to existing transmission rights holders that convert their service to RTO West service. Filing Letter, Attach. A, Exhibit P, p. P-1; § II, p. P-2 - P-3.
[46] The arbitration provisions set forth in Exhibit P to the TOA are available only to existing rights holders which convert their rights to RTO service. *See supra* n. 9.

provides a serious disincentive to conversion. The Commission should reject the attempt of the Filing Utilities to exclude rights holders most directly affected by cataloging from both the cataloguing process and any dispute resolution process arising from cataloguing.

IX. THE COMMISSION SHOULD REVISIT ITS PRIOR APPROVAL OF THE RTO WEST GOVERNANCE STRUCTURE

In its prior order approving the RTO West By-Laws and Trustee Code of Conduct, FERC failed to ensure that RTO West would be governed by individuals who will be free from personal financial interests in entities whose financial performance will depend on the actions of RTO West. FERC's failure severely diminishes RTO West's independence, and FERC therefore erred in concluding that RTO West meets Order 2000's independence requirements.

RTO West's Trustee Code of Conduct leaves a substantial gap in its prohibitions on Trustee financial dealings with entities having a financial interest in the operation of the RTO. Specifically, the proposed Trustee Code of Conduct would prohibit Trustees from holding a financial interest in any "Market Entity" subject to limited exceptions.[47] "Market Entity" is, in turn, defined to include any "Market Participant" as defined by FERC, plus any "Member" of RTO West, and any "Scheduling Coordinator."[48]

Because it relies primarily on FERC's definition of "Market Participant," the definition of "Market Entity" is seriously flawed. As defined by FERC, "Market Participant" includes only an entity that "sells or brokers electric energy, or provides ancillary services to an RTO," 18 C.F.R. § 35.34(b)(2), and therefore leaves out a range of

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[47] See the Trustee Code of Conduct Sec. III.C, attached as Exhibit B, By-Laws of RTO West, Attachment C to the Filing Letter.

entities that in all likelihood will have a substantial interest in the operation of the RTO even though they are not directly engaged in buying or selling power. Hence, many entities that have a substantial interest in RTO West's operations, such as wires companies that are not affiliated with generators, may not qualify as "Market Participants." Similarly, the Trustee Code of Conduct contains no firm prohibition on Trustee financial involvement in entities that have substantial dealings with the RTO not involving the power market. There is, for example, no prohibition on a Trustee owning financial interests in vendors providing real estate, technology, or other goods and services to the RTO.

Recent events have demonstrated the danger arising from a lack of firm prohibitions on financial conflicts of interest in the Trustee Code of Conduct, and require the Commission, as a matter of public policy, to review its prior approval of the governance structure of RTO West. One major factor in the collapse of Enron was the fact that its Board of Directors failed to exercise its corporate oversight role diligently, because it was hamstrung by a series of financial conflicts of interest, including, for example, consulting contracts with Enron and membership on boards of directors of companies doing business with Enron.[49] The Commission should therefore revisit the conclusion in its orders approving the RTO West Stage 1 filing that general language in FERC regulations and the Trustee Code of Conduct is sufficient to prevent such abuse.

Specifically, the Commission concluded that its definition of "Market Participant" would be sufficient to prevent such abuse, pointing to general language in its regulations stating that any entity with "economic or commercial interests that would be significantly

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[48] *Id.* at Sec. I.D, E.

[49] *See, e.g.*, William Neikirk, "Panel Criticizes Enron Board for Failing to Act Quickly to Handle Conflicts," Chicago Tribune, May 8, 2002.

affected" by the RTO's actions can be classified as a "Market Participant."[50] Consequences for any violation of that provision, however, would require that legal action be taken before the Commission, entailing substantial expense, uncertainty and delay. It is just this kind of *post facto* remedy that FERC concluded was inadequate to prevent market abuse.[51] Further, the provision lacks the necessary clarity regarding what kind of interest would be considered "significant", and how direct the effect of RTO actions would have to be on the interest involved to bring it within FERC's purview.

The Stage 1 order also points to general, precatory language in the RTO West Code of Conduct indicating that Trustees "should" avoid conflicts that "might affect the objectivity or independence of his or her judgment."[52] This language is both hopelessly ambiguous and without substantial legal effect. The Commission cannot approve RTO West without firm, enforceable prohibitions that prevent financial conflicts of interest from arising among RTO West Trustees. In light of the Enron scandal, such firm prohibitions are essential if any RTO is to maintain its credibility and to ensure that the RTO is operated in the most efficient manner possible, rather than to enrich the private interests of RTO insiders.

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[50] *Avista Corp.*, 96 FERC Par. 61,058, at 61,175 (2001) (citing 18 C.F.R. Sec. 35.43(b)(2)(ii)).
[51] Order No. 2000, slip op. at 68.
[52] *Avista Corp.*, 96 FERC at 61,175.

X. RELIEF REQUESTED

For the reasons stated above, the Protestors ask that the Commission reject the Filing Utilities' request for declaratory ruling.

Dated this 28th day of May, 2002.

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RTO West
Benefit/Cost Study

Final Report Presented to RTO West Filing Utilities

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EXHIBIT
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Forward

The following consultants provided significant contributions to the conduct of these analyses.

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EXECUTIVE SUMMARY

Tabors Caramanis & Associates (TCA) was contracted by the filing utilities proposing to establish a Regional Transmission Organization (RTO) for the Pacific Northwest (RTO West) to undertake an analysis of the probable benefits and costs of RTO West. The goal of the filing utilities was to provide to all stakeholders an independent quantitative and qualitative analysis that would offer insights regarding the relative merits of establishing RTO West, and its related influences on the commercial, wholesale markets.

The TCA Energy Impact Analysis focused on identifying the patterns of energy transactions and energy flows that would take place *only* with the existence of RTO West—patterns that would be the direct result of increased engineering, economic, and organizational efficiencies arising from the establishment of RTO West. The analyses demonstrated how the behavior of the northwest transmission and energy systems is impacted by market structures, without and with an RTO, and how various market characteristics associated with these two contrasted structures are believed to impact future prices for electricity in the northwest.

The TCA analysis effort, which was conducted from September 2001 through February 2002, was overseen by a northwest stakeholder group which was made up primarily of representatives of the filing utilities and of other interested parties, e.g., representatives of direct service industries, public power systems within the region, and representatives from outside of the RTO West "footprint", e.g., Canada and California. The group provided overall guidance to TCA in defining the scope of work, developing the input assumptions, validating the results, and determining which sensitivity cases were evaluated.

Areas of Study

TCA's analyses covered four principal areas.

1. TCA carried out an Energy Impact Analysis (a simulation analysis) of the engineering economics of operation of the RTO West region and the Western Systems Coordinating Council (WSCC), with and without the existence of RTO West. The study used a simulation tool, GE MAPS, to analyze energy flows, market dynamics, and energy pricing. The energy impact simulation quantified economic benefits across the RTO West grid and the WSCC resulting from the following:

    - Elimination of pancaked transmission rates.
    - More efficient, regional utilization of generating resources.
    - Elimination of pancaked transmission loss charges.
    - Access to a broader market for operating reserves.
    - Increased scheduling efficiency of transmission capacity (through reduced requirements for contract path scheduling limits).

The analysis examined the marginal price of energy to determine the impact to the energy value loads pay and the revenues generators receive. TCA used the GE MAPS modeling system to simulate the operating behavior of the western power system both with and without the existence of RTO West[1]. GE MAPS provides an analytic tool with which to simulate the hourly physical and economic behavior of the power grid. With this system it was possible to model the transactions and flows of energy that would result from the existence of an RTO West agreement in which there was a single tariff for energy flowing in the RTO West system. The effect modeled was to reduce the economic barriers to trade within the region that in turn reduces operating costs and increases flows. A set of input assumptions was mutually agreed upon by the study group.

The analysis calculated, on an hourly basis, the spot market price at each major transmission bus in the west. The analysis quantified the changes between a status quo case (Without RTO case), and a modeling case where structures were changed to represent the operations with an RTO in place (With RTO case). The detailed representation of these "Base" cases is provided in the report.

In addition, several sensitivity cases were performed to isolate benefit drivers and test sensitivities to varying market conditions. These included the following cases:

- Physical System Cases:
  - Low Water Year/High Gas Price
  - New Resource Additions in Montana

- Benefit Driver Cases: With RTO case rerun with each of the following items fixed respectively
  - Loss charged as in Without RTO case
  - RTO export fees set to zero
  - Transmission scheduling limits as in Without RTO case
  - Maintenance schedule as in Without RTO case
  - Isolate the impact of operating reserves

2. TCA carried out benchmarking analyses to estimate the costs of operating an RTO, operating a secondary exchange, market participants' acting as a Schedule Coordinator, and of impacts of lost load due to unplanned outages or impacts of reductions in unplanned outages.

3. TCA conducted qualitative evaluations of further potential impacts of implementing an RTO. These addressed the following areas:

   - RTO focus, coordination, and information exchange.

[1] Note that GE MAPS is a product of the General Electric Corporation, Schnectady, NY. GE MAPS is a Security Constrained Dispatch Model. It calculates the optimal (least cost) dispatch of all generators within the studied system subject to transmission constraints and subject to the possibility of operating outages, hence the description, "Security Constrained Dispatch."

- RTO consolidation of functionality.
- Organizational relationships established by the RTO.
- RTO independence.

4. TCA carried out an analysis of market concentration in the northwest that determined levels of market concentration with and without RTO West.

Findings

TCA's results include benefits and costs (both in terms of Energy Impacts and unquantified benefits) and effects on market concentration.

(A) Benefits

(1) Energy Impact Benefits

The Energy Impact Analysis undertaken by TCA estimates system benefits from two related areas: (1) direct savings in operating costs and (2) system benefits that would result from reduced transmission system congestion.

In the core analysis of the study, the "Base Case" analysis, the 2004 annual marginal cost to serve load under the locational pricing structure proposed for RTO West and modeled in the TCA analysis decreases in the northwest by $1.3 billion[2] as a result of putting in place RTO West. At the same time, the lower prices result in lower generator net revenues of approximately $900 million. The difference between the loads' cost reduction and the generators' net revenue reduction represents the net societal benefit of $305 million for the RTO West region and $410 million for all of the WSCC.

The Energy Impact Analysis further provides insights as to the nature of the overall system cost reductions. For the WSCC,[3] of the $410 million difference between the decreased cost of energy to serve load and the decreased generator net revenues, approximately $239 million represents savings in production costs, predominantly arising from greater efficiency in operations that reduce fuel costs. The balance of the $410 million benefit in WSCC, approximately $171 million, represents the calculated value of decreased congestion costs.

In a locational, marginal-priced energy system (as is envisioned for RTO West), the value[4] of reduced transmission congestion goes beyond the value of the reduction in production costs alone. The same phenomenon is also seen in the RTO West region. TCA's analysis shows the significance of the congestion costs in the northwest. If users

[2] US dollars are used throughout this report, unless otherwise noted.

[3] The WSCC is used here as example. The analysis modeled the entire WSCC, but across the WSCC generation and consumption is balanced in both cases. Within the northwest region, the model shows that the exports increase out of the northwest in the With RTO case, making quantification of the exact attribution of the benefits impossible. The sensitivity cases help to identify the component drivers of the benefits. These are presented in detail in the body of the report.

[4] In such a system, the "value" of the congestion is deemed to be equal to the product of (1) the value of a constrained path and (2) the flow of energy across the path.

were required to pay for the marginal cost of congestion rather than only average or incremental cost, as is the case at present, the costs they incurred would be $171 million less with RTO West than without.[5]

In addition to representing a shift in the cost of managing congestion, the impact can perhaps more importantly be seen as enabling the transmission providers to spend less on transmission reinforcements than would otherwise be needed to counteract high-cost congestion. In this sense, the analysis suggests that a change in generation dispatch enables the region to capture a significant opportunity to avoid needed (transmission) capital expenditures of up to $171 million.

The $171 million congestion impact and the $239 million operating cost savings are demonstrated by the base case analyses.

The sensitivity analyses suggest there are two primary benefit drivers, which reflect the modeling techniques. The pancaked rates seem to have a strong bearing on benefits; by reinstating pancaked loss charges alone, net benefits dropped nearly 40% (to $255 million), with all of this reduction ($157) in the area of reduced congestion rent savings. This sensitivity case was the only case significantly impacting congestion rent savings. Similarly, operating reserves seem to be the only attribute tested that had a strong effect on production cost benefits. The efficient allocation of operating reserves also has a strong bearing on total benefits: isolating the impact of operating reserves showed over 60% reduction in production cost savings (from $239 million to $90 million).

The Energy Impact Analysis is relatively insensitive (4% or less impact on total benefits) to other tested attributes, including maintenance scheduling, contract path scheduling limits, export fees, and low hydro conditions.

From the sensitivity runs, TCA draws the following broad implications:

- Generally, the domination of the northwest system by hydroelectric power provides a relatively efficient bulk power system to begin with;
- Pancaking therefore has a greater impact on the congestion prices across constraints than it does on overall production cost efficiency;
- The ability to further substitute hydro resources for thermal resources for operating reserves, through further regionalization, offers significant benefits.

[5] If the marginal value of congestion were valued explicitly today, the great majority of the congestion costs are borne by the Transmission Owners (TOs). Moving to the RTO structure in this framework would result in a transfer of $180 million cost away from the TOs (or possibly transmission rights holders in an RTO world) and to the loads and generators in the With RTO case.

(2) Qualitative Benefits

A variety of other benefits were identified through industry literature and marketer surveys. Many of these benefits are generally viewed to be material, although the study did not quantify potential values. The following areas were addressed in the analysis:

- Planned outage management may provide more accurate assessments of the effects of proposed maintenance.
- Reduced failure propagation: tightened communications and coordination may reduce conditions that cause failures to propagate.
- Voltage/frequency management: broader information and broader control of transmission and generation resources may reduce voltage and frequency problems.
- Loop/parallel path flow: may provide better management of loop flow through improved access to region-wide information and region-wide scheduling authority and through more efficient pricing of congestion.
- Scheduling, system monitoring, checkouts, and settlements: traditional information exchanges, such as checkouts and interchange accounting, will no longer be required.
- Consolidated control area operation and impacts on reserves and transmission capacity may result in likely increases in available transfer capacity (not captured in the Energy Impact Analysis), reduced requirements for automatic generation control, and sharing of reserves beyond those captured in the Energy Impact Analysis.
- Real-time balancing efficiency may result in a simplification of, and improved efficiency associated with, the balancing function.
- Long-term planning and expansion: long-term transmission and generation additions are likely to be more efficient.

(B) Costs

(1) Benchmarking Costs

TCA's benchmarking analyses focused on identifying the expected annual costs of establishing and operating the RTO itself. On average, the analyses show that the cost to operate an RTO would be approximately \$0.45 to \$0.51 per MWh, or \$127 to \$143 million per year, including the amortized startup costs of the RTO.

The study also examined market participants' potential costs associated with using an secondary exchange and explored the costs of establishing a Schedule Coordinator role for market participants to interface with the RTO. Market participants in the northwest scheduling energy within the RTO can trade energy through an exchange for approximately \$0.10 per MWh, and can receive Schedule Coordination services, for \$0.065 to \$0.08 per MWh.[6] It is noteworthy that the costs of using an exchange, or

[6] These are the fees of the Automated Power Exchange. Some market participants are likely to be able to provide the service within their organizations for much less than this.

drivers to use an exchange, for the most part also exist absent the RTO. Similarly, many of the functions of Schedule Coordination are being conducted today within organizations.

(2) Qualitative Costs

Additional unquantified costs may include the following:

- Generalization costs—the potential loss of unique expertise currently supported by operating smaller, individual transmission systems.
- Complexity costs—additional costs or externalities, beyond the Schedule Coordination role, required to support the RTO structure.

(C) Impacts on Market Concentration

The market concentration analysis indicates the following:

- As a result of maintaining primarily vertically integrated structures, all electricity markets in the RTO West region are highly concentrated, suggesting the potential for—but not necessarily existence of—the exercise of market power.
- The degree of market concentration is not materially affected by the implementation of RTO West.

Assessing Overall RTO Impacts

Although the several study areas reported on here cannot necessarily be collapsed to produce a single conclusion on the quantitative merits of implementing RTO West, the magnitude of the potential savings reported in the Energy Impact Analysis, relative to the industry costs of RTOs, suggests that the benefits could outweigh the costs. The qualitative impacts—predominantly benefits—would tend to strengthen this conclusion. It is the northwest's producers and consumers, however, who must ultimately determine whether the sum of the quantifiable and unquantifiable benefits are greater than the economic and social costs.

1 Organizational Outline

This report is organized as follows.

Section 2 provides background and context for this benefit/cost study.

The largest aspect of this analysis is the assessment of RTO West impacts on energy flows, market dynamics and energy pricing through the use of the quantitative generation and transmission simulation model, GE MAPS. Using the GE MAPS modeling system, this analysis produced quantitative analytic results based on the economic and physical operation of the regional power system. The impact study approach, detailed assumptions, and base case and sensitivity results are presented in Section 3.

TCA performed quantitative benchmarking analyses for other benefit/cost elements, such as RTO, and exchange and Schedule Coordination costs. The benchmarking elements are presented in Section 4. Qualitative investigation of other potential impacts of an RTO is outlined in Section 5. Section 6 contains the Market Concentration study, including approach and findings.

In order to provide a manageable printed document, detailed (and voluminous) output data associated with the Energy Impact Analysis and the market concentration study have not been included with this report. These data are available for electronic downloading on TCA's web site at www.tca-us.com/publications when made publicly available by RTO West.

2 Background

The Benefit/Cost Study was commissioned by RTO West Filing Utilities for the purpose of evaluating the qualitative and quantitative implications of developing and implementing RTO West.

A previous benefit/cost study[7] was performed by a northwest stakeholder study group using the modeling tool AURORA. Assumptions in that energy analysis included the use of average water conditions and transactions at market clearing prices. The AURORA model did not attempt to reflect dynamic congestion management[8], and although the modeling effort identified some benefits due to removal of pancaking transmission rates, the modeling results did not produce reliable conclusions about the benefits and costs.[9] The previous study also addressed RTO costs by developing an expected budget for RTO West, and it identified savings expected from lower quantities of regulating reserves being required under an RTO.

The Filing Utilities established a work group which involved Filing Utility representatives and other interested parties for the purpose of scoping the Competitive Solicitation, interviewing and selecting project consultants, scoping the evaluation, defining and specifying assumptions and data input, specifying sensitivity analyses and evaluating results. The stakeholder work group directing the present benefit/cost study selected a study methodology that included a detailed modeling of the transmission system and that looked into other benefit and cost impacts of RTO West in more depth. The stakeholder group conducted a competitive selection process in the summer of 2001, worked with TCA to develop a detailed scope of work, and contracted with TCA to perform work under this scope in November 2001.[10] Following those initial steps, TCA and the study group worked closely to develop the assumptions to be used in the analyses.

TCA presented the results of its preliminary analyses on February 4, 2002.[11] TCA and the study group reviewed the results, refined the assumptions, and identified sensitivity cases to be run. This report presents the results of the ultimate modeling activities and the complete results of the other benefit/cost elements.

7 RTO West Potential Benefits and Costs, October 23 2000.
8 Op Cit. p 5.
9 Op Cit, p 23.
10 Posted at http://www.rtowest.org/Stage2BenCstMain.htm
11 Ibid.

3 Energy Impact Analysis: GE MAPS Study

TCA conducted a quantitative analysis of the WSCC system under two scenarios: a status quo case in which RTO West is not implemented ("Without RTO") and a case in which RTO West is implemented ("With RTO"). The Energy Impact Analysis used the GE-MAPS model[12], which incorporated the operating procedures and contractual and physical transmission constraints currently used or proposed for the WSCC. The analysis provides insight into the theoretical economic operation of the WSCC markets With and Without RTO.

The analysis shows that there are economic efficiencies to be realized by regionalizing the operation of the electric power market. These results are based on input assumptions that the RTO West Benefit Cost Work Group (work group) considered as reasonably expected conditions for the year 2004 (including the current RTO West proposal, fixed hydro schedules, and economically efficient markets with marginal cost bidding). Most realistically, the benefits fall within a range, and these results show the expected value of benefits given the base-case assumptions. The results of the sensitivity analyses are presented, and they offer insights into the sensitivity of the results to certain assumptions and the relative drivers of the benefits.

3.1 Expected Benefits of RTOs

The economic benefits of RTOs are many, including the following:

- Increased economic efficiency from eliminating pancaked[13] transmission rates and pancaked transmission loss charges;
- Sharing of operating reserves;
- Improved congestion management and internalization of loop flows;
- Coordinated maintenance and scheduling of generation and transmission;
- Increased competitiveness of markets;
- Lower transaction costs (one-stop shopping) and simplified business practices, especially for small players;
- Increased ATC over major transmission lines; and
- Other economic benefits such as coordination of system expansion and planning, adoption of a single OASIS site, and improved reliability on a regional basis.

Economic efficiency, sharing of operating reserves, and improved congestion are addressed as part of this Energy Impact Analysis. The other benefits are addressed qualitatively in Section 5 of the report.

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[12] GE-MAPS is a Multi-Area Production Simulation Software developed by General Electric Power Systems and proprietary to GE.

[13] "Pancaked" refers to the additive nature of the charges when energy is transported across multiple transmission areas.

3.2 Measuring Benefits with the Energy Impact Analysis

Two metrics were used in the Energy Impact Analysis to quantify the benefits of RTOs:

1. Production cost savings (fuel and variable Operating & Maintenance costs)
2. Social welfare (consumers' and producers' surplus) benefits.

The social welfare, consumer and producer surplus are economic terms that are often used in cost/benefit analyses. It is assumed that a decision is economic or cost-effective if the net increase in social welfare exceeds the cost. In practice, this concept is applied by governments to aid decisions that affect society, e.g., in deciding to build roads or preserve wilderness areas, in building recreational sites, or requiring environmental mitigation measures. This concept is very useful because it shows the impact on the society as a whole rather than on a portion of it. For example, lowering energy market clearing prices in any given area could reduce generators' profits, but, on the other hand, it reduces load payments. If the measure is only producers' surplus or producers' benefit, then lowering energy prices might seem harmful, and lowering energy prices is a bad idea; however, if we look at both sides of the equation and there are net benefits, then lowering prices is a good idea. Also, using this concept avoids the problem of allocating the benefits or deciding who is getting the benefit and thus avoids dealing with regulatory and contractual issues that determine how the benefits get allocated. Throughout the analysis in this report the impact on consumers and generators is determined separately, as well as the net impact on society.

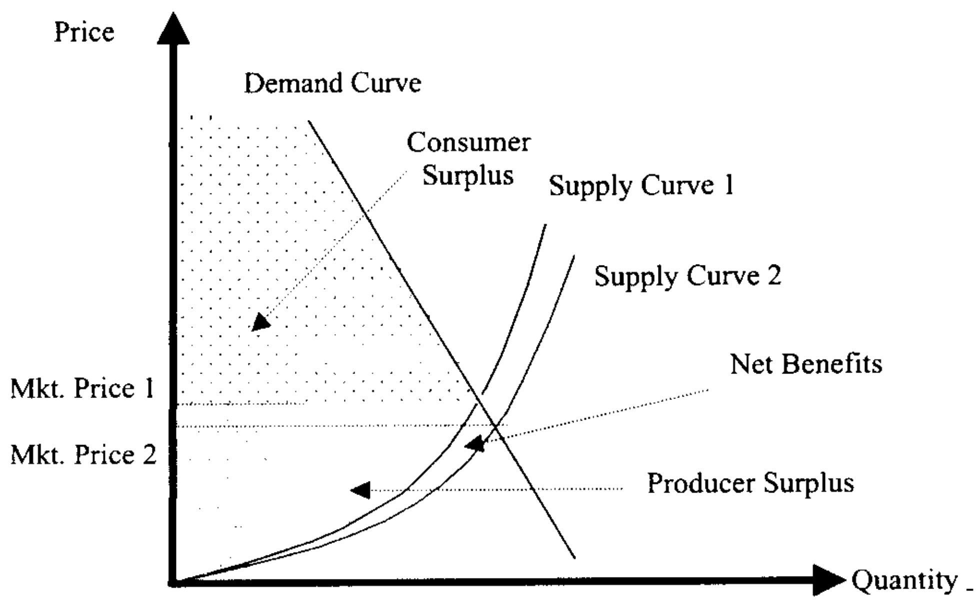
The social welfare is expected to be the same as the production cost savings because inelastic demand was used in the model and thus demand is fixed and the same in both With and Without RTO cases. Additionally, there are three players in this market: consumers and producers of energy, and the transmission rights owners. The impact of implementing RTO on these three players is quantified.

To illustrate how to quantify the benefits of RTOs using these metrics, consider how eliminating pancaked transmission rates increases economic efficiency:

> *Production cost savings:* Eliminating pancaked transmission rates increases the economic efficiency of dispatching generation resources to meet demand at lowest cost, and thus lowers the total cost of producing electricity. Without pancaked transmission rates, during peak hours, for example, high-price areas could buy available steam gas-fired generation from other areas instead of starting a more expensive peaking unit. With pancaked transmission rates, this peaker would have been more economical given the added cost to move power from the steam unit, even though it is much less-efficient than a steam gas-fired unit or a combined-cycle unit.

Social welfare benefits: Consider the supply and demand curve in Figure 1. As the supply curve shifts right due to more economic dispatch of generation resources, there is a net increase in both consumer and producer surplus. Eliminating pancaked transmission rates will increase market prices in some areas and decrease prices in other areas. Producers benefit in increased-price areas, while consumers give up value, and vice versa for areas with lower prices. Thus, consumer surplus increases in areas where prices go down and producer surplus increases in areas where prices increase. The net benefit to both consumers and producers in all areas is the increase in social welfare. In addition, exporting areas will realize a net benefit even when prices go up, since generation exceeds demand.

Figure 1: Producer and Consumer Surplus



Similar to eliminating pancaked transmission rates, eliminating pancaked loss charges increases economic efficiency. Currently, most regions have tariffs that include charges for losses based on average loss factors. When transactions cross more than one control area, these loss charges are pancaked. Eliminating the transmission loss charge pancaking, and charging for losses on a regional basis instead, eliminates the penalty effect of moving energy within RTO West and would increase the economic efficiency of dispatching generation resources.

Sharing operating reserves across the RTO West region also leads to lower operating costs. Carrying reserves on the most efficient resources over a wider region will lower operating costs. Take the example of a system with large hydro generation, which is able to carry spinning reserves at a much lower cost than a system with mostly thermal units, and this benefit could be shared among systems that have predominantly hydro generation and systems that have predominantly thermal generation.[14]

Another benefit of RTOs is improved congestion management and internalization of loop flows through the elimination of contract path scheduling. Current contract path limits are set to protect the system in the absence of centralized control and an information collection center. The objective of these contract path limits is to limit the impact of loop flow on neighboring control areas by assuming that there are no loop flows. Eliminating contract path scheduling limits increases the utilization of the transmission system, reduces total production cost, reduces transmission congestion cost, and lowers locational prices.

3.3 Using the MAPS Model to Determine Benefits

3.3.1 Basic Model Representation

The GE MAPS model is a security-constrained dispatch model that simulates the operation of the electricity market over time. It assumes marginal cost bidding,[15] performs a least-cost dispatch subject to thermal and contingency constraints, and calculates hourly, locational-based marginal prices for electricity. Zonal prices can be calculated either as load-weighted averages or as simple averages of locational prices. The congestion cost is calculated as the shadow price[16] multiplied by the power flow on each interface. Because it is reasonable to assume that real markets are not perfectly competitive, the simulated prices represent the lower bound of what actual market prices are likely to be.

The GE MAPS simulation is consistent with the congestion management scheme envisioned by RTO West. GE MAPS simulates the electricity market by dispatching resources to serve load in a least-cost manner. The bidding strategy that is assumed is based upon the marginal cost of generation and therefore reflects the locational marginal price of electricity at specific nodes; nodal data can be aggregated to whatever level (utility, region, state, etc.).

The GE MAPS simulation is also consistent with the RTO West pricing scheme, which is based upon a load-based, company rate concept. More specifically, the RTO West pricing scheme expects to collect most of the embedded cost of transmission facilities from loads, although a portion of the embedded costs are expected to be collected through transitional mechanism, called the Transmission Reservation Fee (TRF). GE MAPS

[14] The RTO should also enable lower reserve requirements, as discussed in Section 5, though the Northwest may already have reserve sharing agreements to take advantage of load and generation diversity. The Energy Impact Analysis did not assume any reductions in total requirements, but rather only considered the optimized dispatch of reserve resources.
[15] However, that assumption can be overridden, implementing strategic bidding behavior, but such effort is not trivial and the study group chose not to pursue this sensitivity case.
[16] The "shadow price" represents the marginal value of a constrained path and is calculated by GE MAPS.

applies the TRF ($3.60/MWh), plus a $0.20/MWh administrative fee, to all transactions that exit the RTO West footprint.

3.3.2 Input Assumptions

The following inputs assumptions were used in the Energy Impact Analysis:

- A load forecast based on most recent forecast as provided by RTO West.
- Fuel price forecasts based on the EIA forecast for natural gas.
- A transmission system configuration based on a load flow representation that includes all transmission upgrades for summer 2004, as provided by RTO West.
- Environmental adders based on expected NOx regulations for 2004.[17]

Details of these and other inputs to the model are described in Attachment 1.

In addition, the Energy Impact Analysis employed basic assumptions about commitment, given fees, and about capacity markets.

The RTO boundaries were defined based on today's boundaries for the California ISO, proposed boundaries/membership for RTO West, and proposed membership for WestConnect. Note that it was assumed that all utilities in the northwest participate in RTO West, **OR** that those entities that do not participate have no impact on the operation of RTO West.

TCA used a regional installed capacity market to accurately represent the transmission system capability, the fact that excess installed capacity in Alberta is not that useful to British Columbia, and so on. Each region was assumed to have a 16% installed capacity reserve margin requirement except Alberta and British Columbia, where an 18% reserve margin requirement was used. Note that TCA did not evaluate the impact of establishing RTO West on the Installed Capacity market clearing prices or the value of installed capacity if there are no explicit markets in the WSCC.

3.3.3 With and Without RTO West Scenarios

The Energy Impact Analysis base case compared two scenarios: a status quo case, assuming no RTO implementation in the northwest (Without RTO), and a case representing operations with RTO West in place (With RTO).[18] The RTO West benefits were deemed to be equal to the change in production cost and the change in producer and consumer surplus between the two cases.

The following represents a summary of the With and Without RTO cases. Detailed discussion for each major attribute is provided in the sections that follow.

[17] By request of the RTO West benefit/cost study group, however, TCA did not include the NOx environmental adders in generators' simulated bid prices.
[18] In the With RTO case, an RTO in the Southwest was also modeled with similar market conditions to that represented for the RTO West.

The With RTO West market conditions were defined as follows:

- No pancaked transmission or loss rates, only a single region-wide wheel-out rate applied at the region boundaries;
- No contract path scheduling limits;
- Carrying reserve on most efficient resources within the entire RTO West region, with the reserve requirements based on the region's hourly load;
- Optimizing unit commitment and least-cost security-constrained dispatch on a region-wide basis (all generation resources within the RTO area);
- Scheduling maintenance of generation units according to regional load; and
- Hourly hydro generation predefined, based on average historic output; scheduling hydro generation (outside PNW) against regional load.

The Without RTO West market conditions were defined as follows:

- Pancaked transmission wheel-out rates (on company basis);
- Pancaked loss wheel-out rates;
- Contract path scheduling limits in place;
- Carrying reserves on individual company's units and requirements on company's hourly loads;
- Scheduling maintenance of generation unit according to individual company's loads; and
- Hourly hydro generation predefined, based on average historic output; and scheduling hydro generation (outside PNW) against company's loads.

Note that the first three characteristics in the preceding list represent financial or contractual characteristics, rather than being determined by the engineering characteristics of the power system.

3.3.4 Treatment of Wheeling Charges

In the With RTO case, wheeling charges for transactions, or energy flows, between different RTOs were modeled. In this case, power can be moved from any generator in an RTO to any load in that RTO without paying pancaked wheeling charges. However, there are wheeling charges at each of the RTO's boundaries (RTO West, California ISO, and WestConnect). Wheeling charges apply primarily to power flowing out of a region or control area (wheel-outs and wheel-throughs). A small number of utilities also had wheel-in charges.[19] It was assumed that in each RTO the load would pay its local transmission rate, irrespective of that load's source of electricity.

[19] This is the case for BPA and IID. For these entities the modeling assumptions were based on these entities' tariffs and discussions with BPA staff.

For the Without RTO case, wheeling charges were used for each existing transmission owner's service area, based on the rates filed in their transmission tariffs. These charges are assessed on wheel-out and wheel-through transactions.

Table 1 shows wheeling rates used in both the With RTO and Without RTO cases.

The following examples demonstrate the application of wheeling rates in the Energy Impact Analysis.

1. Generation located in the BPA area selling power off the BPA system pays BPA wheeling rates in the Without RTO case.
2. Generation located outside of BPA and delivering energy through and out of the BPA system is considered to represent a wheel-through and also pays BPA wheeling rates in the Without RTO case.
3. Energy moving from a BPA generator to a BPA load, on the other hand, is not assessed a wheeling charge in either case.
4. Generation from a BPA generator to a California load pays the pancaked wheeling charges along the least-cost path from BPA to California in the Without RTO case, and pays only the RTO West export fee in the With RTO case.
5. In the Without RTO case, a generator in Montana serving BPA load pays
    a. the Montana Power Company wheel out rate,
    b. the BPA Montana intertie, and
    c. the BPA network charge for wheeling into BPA[20] (BPA network and intertie rates are pancaked. The same is true for the southern intertie.)
6. In the With RTO case, the above generator in Montana selling to BPA incurs no wheeling charges.

An in-area transmission service charge is not explicitly modeled for the following reason. The load pays the transmission service charge irrespective of where its power originates, and thus the transmission service charge is a sunk cost that should not affect the dispatch decision. In both the With RTO and Without RTO cases, the loads are exactly the same. Thus, transmission service payments by in-area loads will not be impacted by other aspects of the cases. Therefore not modeling such payments has no impact on the outcome of the modeling or the collection of load-based transmission revenues.

The revenues from wheeling charges differ between the With RTO and Without RTO cases. Considering wheeling charges internal to RTO West, there may be a cost shifting *among* RTO West members but zero impact on net benefits *across* RTO West. There is a wealth transfer to/from the RTO West, the CA ISO, and the Southwest RTO only to the extent that total export charge revenues differ in the With RTO and Without RTO cases.

[20] TCA tested this assumption by setting the wheeling-in charges to zero for both BPA and IID. The results of this simulation show a deminimus change in either total production cost savings or WSCC-wide net savings.

TCA did not quantify the impact of the changes in wheeling rates into and out of RTO West as part of the RTO West benefits.[21]

Table 1: Wheeling Rates Used in the With and Without RTO Cases

Wheeling Charges ($/MWh)

Region / Utility	*With RTO*	*Without RTO*	*Region / Utility*	*With RTO*	*Without RTO*	*Region / Utility*	*With RTO*	*Without RTO*
RTO West	3.80	0.00	California			WestConnect	3.00	0.00
Avista Corp.		1.50	PG&E - high voltage only	1.77	1.77	Arizona Public Service		3.50
Idaho Power Company		1.50	PG&E - low voltage	3.76	3.76	El Paso Electric		5.50
Montana Power Co.		4.48	SCE - high voltage only	2.05	2.05	Public Service of New Mexico		2.84
PacifiCorp		1.50	SCE - low voltage	2.28	2.28	Salt River Project		4.12
Portland General Electric		1.50	SDG&E - high voltage only	2.01	2.01	Texas-New Mexico Power	0.00	5.34
Puget Sound Energy		1.50	SDG&E - low voltage	4.85	4.85	Tucson Electric Power		6.52
Sierra Pacific Resources	0.00		California - Oregon Border (COB)	1.83	1.83	WAPA Lower Colorado		2.13
Zone A (Sierra Pacific Power)		3.92	Palo Verde intertie	2.03	2.03	WAPA Rocky Mountain		4.17
Zone B (Nevada Power)		1.66	Nevada - Oregon Border (NOB)	1.84	1.84	WAPA Upper Missouri		4.04
Bonneville Power Administration			Mead intertie (MEAD - WALC)	2.05	2.05	Imperial Irrigation District		1.00
Network		1.50	Victorville intertie	2.05	2.05			
Southern intertie		2.20	Sylmar AC	2.05	2.05			
Montana intertie		3.56	LADWP	9.00	9.00			
BC Hydro		3.98						
Alberta (includes losses)	3.00	3.00						

Notes:

With RTO West case: RTO West tariff is $3.60, plus a $0.20 administrative charge.
BPA charge applies to wheel-outs and wheel-ins. When wheeling power over an intertie, the intertie rate is added to the network rate.
California and WestConnect charges apply to wheel-outs, except for Imperial Irrigation, which applies to wheel-ins and wheel-outs.
No charges apply to flows within the California ISO (PG&E, SCE, and SDG&E) for both scenarios.

3.3.5 Modeling of Charges for Losses

In the Energy Impact Analysis, charges for losses were added to the transmission tariff rates and were applied to power flowing out of a region or control area (wheel-outs and wheel-throughs). As with the treatment of a wheeling charge, a loss charge[22] was applied only to power flowing out of an RTO in the With RTO case; transactions within an RTO were not charged for losses. In the With RTO case, RTO West was separated into two sub-regions, BC Hydro and the rest of RTO West, applying respectively BC Hydro's loss rate or using a load-weighted average loss factor of individual companies for the balance of RTO West. The tariff losses were applied to flows between the two sub-regions and flows to external regions.

Note that since GE MAPS does not calculate marginal loss factors on an hourly basis and thus cannot determine the actual losses on the system, TCA modeled the transmission losses on the DC lines only. GE MAPS uses a set of fixed loss factors based on the specified load flow case and scales these factors up or down as the load increases or decreases with respect to the base case (i.e., it assumes a linear relationship between transmission losses and load on the system). As long as the power flows on transmission lines do not change direction, this is a reasonable approximation, but as is well known in

[21] However, the higher single export rate in the With RTO case counter balances the reduced pancaking levied in the Without RTO West case.

[22] The losses charge was calculated using a loss factor and an average energy price around $30/MWh.

the west, the flows reverse direction depending on the season. As a result, the GE MAPS logic to calculate marginal losses was not used, and the impact on market clearing prices of changing physical losses was not determined. Rather, only financial fees for losses, and the resulting impact on the dispatch and market clearing prices of eliminating the pancaking of these fees, were incorporated into the Energy Impact Analysis. In the Without RTO West case, tariff loss rates were charged at the boundaries of control areas using loss factors by company. Both the With and Without loss factors are shown in Table 2.

The Energy Impact Analysis also treated loads as if they were located at the generation bus, thus capturing the cost of transmission losses, but not any impacts of distribution losses.[23]

Table 2: Loss Rates With and Without the RTO

Loss Factors

Region / Utility	*With RTO*	*Without RTO*	*Region / Utility*	*With RTO*	*Without RTO*	*Region / Utility*	*With RTO*	*Without RTO*
RTO West	2.83%	0%	California			WestConnect		
Avista Corp.	0.00%	3.00%	PG&E - high voltage only	3.0%	3.0%	Arizona Public Service	included in wheeling charge	2.50%
Idaho Power Company		3.60%	PG&E - low voltage			El Paso Electric		3.00%
Montana Power Co.		4.00%	SCE - high voltage only			Public Service of New Mexico		3.00%
PacifiCorp		4.48%	SCE - low voltage			Salt River Project		2.30%
Portland General Electric		1.60%	SDG&E - high voltage only			Texas-New Mexico Power		3.34%
Puget Sound Energy		2.70%	SDG&E - low voltage			Tucson Electric Power		3.30%
Sierra Pacific Resources			California - Oregon Border (COB)			WAPA Lower Colorado		3.00%
Zone A (Sierra Pacific Power)		2.34%	Palo Verde intertie			WAPA Rocky Mountain		5.50%
Zone B (Nevada Power)		1.32%	Nevada - Oregon Border (NOB)			WAPA Upper Missouri		4.00%
Bonneville Power Administration			Mead intertie (MEAD - WALC)			Imperial Irrigation District		3.0%
Network		1.90%	Victorville intertie					
Southern intertie		3.00%	Sylmar AC					
Montana intertie		3.00%	LADWP	4.8%	4.8%			
BC Hydro	6.05%	6.05%						
Alberta (included in wheeling charge)	-	-						

Notes:

BPA loss factor applies to wheel-outs and wheel-ins. When wheeling power over an intertie, the intertie rate is added to the network rate.
California and WestConnect losses apply to wheel-outs, except for Imperial Irrigation, which applies to wheel-ins and wheel-outs.
No charges apply to flows within the California ISO (PG&E, SCE, and SDG&E) for both scenarios.
No charges apply to flows within Westconnect for With RTO West scenario.

3.3.6 Contract Path Limits

TCA used contract path power flows limits from a study done for the Western Governors' Association[24] for the Without RTO case only. Wheeling charges and losses along these paths were calculated as previously described. If more than one tariff existed along a contract path, a simple average of the tariffs along that path was used.

[23] This is generally seen as reasonable, as the implementation of an RTO in and of itself would likely not significantly affect the distribution company charges.
[24] "Conceptual Plans for Electricity Transmission in the West, Report to the Western Governors' Association," August 2001. Available on the website: www.westgov.org.

RTO West and WSCC provided the contract path scheduling limit data, and the limits are listed in Attachment 1.

No contract path flows were used in the With RTO case; only real power flows and physical constraints were used.

3.3.7 Operating Reserves

The operating reserves are set by WSCC as a percentage of load in each control area. TCA modeled the operating reserve requirement as 7% of the load in each control area, of which 50% was spinning reserve and 50% was non-spinning reserve. The spinning reserve market affects the energy market prices because the units that spin cannot produce electricity under normal conditions. The energy prices are higher when reserves markets are modeled.

In the With RTO case, TCA assumed that reserve levels are 7% of each reliability region load (see three regions below) carried on most efficient units in the region, rather than 7% of individual control areas load carried on their own units. There is currently a reserve-sharing agreement among NWPP control areas; the current requirement is that each control area carries its own reserves, which is not the same as having a regional requirement.[25] This results in more economic allocation of reserves. TCA defined operating reserves for three regions (BC Hydro, Montana–Utah, and the balance of the northwest) in the With RTO scenario, based on input from the study group. These regions were used in order to capture the fact that energy from the reserves has to be deliverable to the site of the contingency, and therefore this locational requirement compensates for significant transmission constraints. Table 3 lays out the requirements in both cases.

It was assumed that only a small percentage of generation units' capacity can provide spinning reserves because there are ramp-up constraints that prevent units from delivering energy needed within short periods (usually ten minutes). This percentage varies by unit type, as listed in Attachment 1. It was assumed that a portion of unloaded hydro resources (20%) could be used to meet the spinning reserves requirements[26].

[25] There is currently a similar reserve-sharing agreement among Arizona / New Mexico / Southern Nevada control areas.

[26] Source: communication with BPA staff.

Table 3: Reserves in With and Without RTO Cases

Operating Reserves

	With RTO West	*Without RTO West*
Reserve Requirement	7% reserves 1/2 spinning, 1/2 non-spinning	7% reserves 1/2 spinning, 1/2 non-spinning
Geographic Basis	Three regions: 1. BC Hydro 2. Northwest 3. Montana-Utah	Company-by-company basis

3.3.8 Physical Transmission Constraints

The same data for physical transmission constraints were used for both cases, including seasonal ratings for lines in the northwest as specified by RTO West. Ratings from the WSCC 2001 Path Rating Catalog were used for other areas. TCA included all proposed transmission projects expected to come on-line by 2004.

Phase angle regulators are centrally controlled and optimized to minimize total production cost in both cases, but they effectively minimize loop flow in the Without RTO case, and attempt to hold power flows according to the schedules. RTO West provided the load flow data, based on the list of transmission upgrades and data contained in the Western Governors' Association (WGA) study, as well as the seasonal path ratings. All of these are listed in Attachment 1.

3.3.9 Maintenance Schedule for Generation Units

The GE MAPS feature of scheduling maintenance of thermal generation units was used to levelize the reserves on an annual basis (reserves being available capacity minus peak load on a weekly basis).

In the Without RTO case, it was assumed that companies schedule the maintenance of their units such that they levelize their own reserves on an annual basis. For example, if a company's load peaks in the summer, it will schedule little or no maintenance in that season; similarly, if a company's load peaks in the summer and winter, it will schedule no maintenance in these two seasons. For the With RTO case, it was assumed that the RTO will coordinate the scheduling of generation unit maintenance across all units in the RTO region, and that the maintenance schedule will be determined by levelizing the reserves for the entire region on an annual basis. This effectively means a better and more economic scheduling of maintenance on generation units.

Note that the RTO-coordinated maintenance schedule could yield company-specific schedules that are more expensive to a few individual entities and yet are more efficient on a system-wide basis. This is therefore an issue to consider, and more importantly it is something that cannot be achieved without coordination by an RTO or a similar institution.

3.3.10 Generation from Hydro Units

The hourly generation schedule of hydro units in the northwest and British Columbia was provided by RTO West based on average hydro conditions and was used in the GE MAPS in both With RTO and Without RTO cases. The Benefit Cost Work Group decided on this approach to ensure that the model captured all environmental, operational, and other constraints that determine generation from hydro units. The work group fixed the hydro schedule because the "hydro operations in the Pacific Northwest are driven largely by non-power constraints associated with fish and wildlife mitigation, flood control, irrigation, navigation, etc." [27]

The hydro generators in California (including pump storage units) are scheduled against California ISO load in both With RTO and Without RTO cases. Only hydro generation in the southwest and small hydro units in the northwest and Canada are scheduled differently in the With RTO and Without RTO cases; in the Without RTO case, these units are scheduled against a company's load, while in the With RTO case they are scheduled against regional load, i.e., the RTO load in which these units are located.

The GE MAPS model generally does not dispatch hydro generation to relieve transmission congestion. However, if the locational price at the generation unit is very low (less than $5/MWh), then MAPS backs down generation from that unit to relieve congestion; that is, backing down the hydro unit is the most economic and maybe the only alternative to relieving congestion. Also, GE MAPS does not increase generation from hydro resources to relieve congestion. This modeling assumption impacts the results in both cases because thermal units are used for congestion management in both cases. It is not clear how modeling fixed hydro schedules biases the results compared to reality. Also, to the extent that the operational and environmental constraints prevent dispatching hydro to relieve transmission congestion, the model is replicating reality.

Overall, TCA believes that this assumption produces a conservative representation of benefits, because the hydro generation is not flexible enough to take advantage of the changes in market conditions due to the implementation of RTO West. Thus there could be additional benefits from more optimal scheduling of hydro resources, which are not captured in this quantitative analysis.

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[27] Communication with Carol Opatrny.

3.3.11 Regional Least-Cost Dispatch

The GE MAPS feature of committing generation resources on regional basis (equivalent of the day-ahead market) and dispatching generation units on the WSCC-wide basis was used in both the With RTO and Without RTO cases. The objective was to capture all the economy transactions that currently take place among various entities in the WSCC, even without an RTO, and those expected by establishing RTO West. This modeling assumption represents an assumption that the wholesale electricity market in the WSCC is currently very efficient and that RTO West will not increase the efficiency of the trading market. This is a conservative assumption that does not capture the increased efficiency of the WSCC market that would arise (if any) from implementing RTO West.

3.4 Summary of Results - Base Cases

The results of the GE MAPS analysis are summarized in this section. The section provides the quantification of benefits, changes in energy prices, and resulting transmission constraints for the base case and sensitivity analyses. All financial values shown in this section are expressed in real year-2000 dollars. All dollar values in this and other report sections are in U.S. dollars unless otherwise stated.

The quantification of benefits from the GE MAPS analysis is based on comparisons between the two scenarios[28] and includes generation production cost, load payments based on spot market purchases, and generation revenues based on spot market payments. The comparisons are made both across the WSCC system and, where possible, for the RTO West region.

Results are presented for both the changes in the value of energy to loads[29] and the generators' revenues (based on the value of energy at the generator busses).

As reported, both the load costs and the generator revenues consist of several components: energy, daily uplift, spinning reserves, and other factors not modeled (Installed Capacity, Automatic Generation Control and other ancillary services). The energy revenue or payment is the marginal value of energy at each load bus times the

[28] Capturing benefits in this way removes the majority of concerns regarding inaccuracies in modeling variables, as the great majority of parameters act equally in both the With and Without RTO cases. By examining differences between the cases, therefore, adverse impacts of a majority of modeling assumption inaccuracies are eliminated.

[29] As was earlier stated, the Energy Impact Analysis calculates the marginal price of energy. For calculating benefits, the value of the energy consumed by the loads is calculated as the marginal price of energy at each load bus times the load consumption at that bus. These are the values that are compared between the With and Without RTO cases. Throughout this analysis, other, more concise terms are used to represent this value. As such, it should not be assumed that when terms such as "Load Energy Payment", or "costs to loads", are used TCA was presumptuous enough to know what loads would actually pay. What loads actually will pay depends on many factors, including rate design, which are outside the scope of this wholesale analysis. The analysis herein is limited to the value of the marginal value of the wholesale energy.

volume of energy delivered or consumed. Daily uplift is an accounting of funds needed to "make generators whole" across each operating day, should the most economic solution dispatch a generator that subsequently does not recover its startup costs through energy net revenues.

Uplift is a construct in use in most of the location-based marginal-priced markets in the East. Spinning reserves represent the sum of funds paid to resources for provision of spinning reserves or charged to loads for their having received the spinning reserve service. It is useful to keep in mind that when benefits are netted across load and generation sectors, the changes in daily uplift and spinning reserve payments net out because those two categories of funds are equally paid and received by loads and generators respectively.

3.4.1 Summary of Benefits - Base Cases

This section presents the Energy Impact Analysis results for the fundamental cases modeled as the "base cases."[30]

Table 4 presents the results of the base case analysis. The figures in the table, as with all similar results tables in this section, represent the difference of the modeling results in the With RTO and the Without RTO cases. Columns A and F show that energy prices go down, causing load payments and generators' revenues to go down, in the With RTO case compared to the Without RTO case. Column C shows that the spinning reserve market prices also go down, lowering both load payments and generators revenues; having a similar impact as energy prices. Since load and generation see the same spinning reserve savings, this has no net impact. However, spinning reserves have an indirect net impact through the energy prices, as is to be seen in the sensitivities in the next section.

Note that RTO West production costs increase simply because exports increase as pancaked wheeling charges are eliminated.

[30] The results here differ from the preliminary results presented on February 4, 2002 in two ways: first, the wheeling charges for BC Hydro, Montana Power Company, Nevada and Sierra Power were modified. Second, the cost and revenues from purchases and sales from outside the WSCC were included.

Table 4: Summary of Benefits, Base Cases

Summary of Benefits ($M)- Difference Between With and Without RTO - Base Case								
	A	B	C	D	E	F	G	H
Sub-Region	Load Energy Payment	Uplift Payment	Spinning Reserve Payment	Total Load Payment A+B+C	Generation Cost	Generator Energy Revenue	Generator Net Revenue B+C+F-E	Net Impact G-D
ALBERTA	(53)	0	(1)	(54)	(8)	(51)	(44)	10
BRITCOL	(70)	(2)	(3)	(75)	(87)	(147)	(65)	10
CA ISO	(526)	13	(50)	(563)	(174)	(711)	(573)	(10)
Rocky Mtn	(266)	0	(77)	(343)	(58)	(253)	(272)	70
Rest of RTO West	(1,174)	1	(209)	(1,383)	124	(755)	(1,087)	295
W Connect	(426)	(1)	(111)	(539)	(37)	(429)	(504)	34
Total	(2,516)	11	(451)	(2,956)	(239)	(2,345)	(2,546)	410

The table shows WSCC-wide savings of $410 million; $239 million are due to generation cost savings due to more efficient dispatch, while the remaining $171 million are from lower transmission rents due to lower transmission congestion causing lower congestion charges.

In these base cases, the 2004 annual marginal cost to serve load under the locational pricing structure proposed for RTO West and modeled in the TCA analysis decreases in the northwest by $1.3 billion[31] as a result of implementing RTO West and WestConnect. At the same time, the lower prices result in lower generator net revenues of approximately $1.1 billion. The difference between the loads' cost reduction and the generators' net revenue reduction represents the net societal benefit of $305 million for the RTO West region and $410 million for all of the WSCC.

3.4.2 Explanation of Benefits

The Energy Impact Analysis further provides insights as to the nature of the overall system cost reductions. For the WSCC,[32] of the $410 million difference between the decreased cost of energy to serve load and the decreased generator net revenues, approximately half ($239 million) represents savings in production costs, predominantly arising from greater efficiency in operations that reduce fuel costs.

The balance of the $410 million in WSCC, approximately half, represents the calculated value of decreased congestion rents, which consist of transmission congestion, transmission wheeling and loss charges. In a locational, marginal-priced energy system

[31] For RTO West impacts the totals from the "RTO West W/O BC" and the "Britcol", otherwise broken out for further information, are added.

[32] The WSCC is used here as an example. The analysis modeled the entire WSCC, but across the WSCC generation and consumption is balanced in both cases. Within the Northwest region, the model shows that the exports increase out of the northwest in the With RTO case, making quantification of the exact attribution of the benefits impossible. The sensitivity cases help to identify the component drivers of the benefits. These are presented in detail in the body of the report.

(as is envisioned for RTO West), the value[33] of reduced transmission congestion[34] is greater than the value of the reduction in production costs. The same phenomenon is also seen in the RTO West region. TCA's analysis shows the significance of the congestion costs in the WSCC. If users were required to pay for the marginal cost of congestion rather than only average or incremental cost, as is the case at present, the costs they incurred would be $171 million less with the RTO than without.[35]

In addition to these benefits described across the WSCC, specific benefits accrue to the northwest, as the northwest generators are seen as more competitive in the With RTO case and export more energy out of the northwest. This explains why generators' operating costs in the northwest increase with the RTO; although more efficient generators are running to meet the needs of the northwest, the northwest generators are exporting significantly more energy out of the northwest in the With RTO case than in the Without RTO case. The table demonstrates that within the WSCC the great majority of benefits from RTO West accrue to the northwest, rather than to neighboring regions.

Finally, in the analysis hydro generation in the northwest consists of a pre-defined schedule so as to ensure that the MAPS dispatch mechanism does not violate environmental limits. This results in some unrealistic system behavior. For example, to the extent that hydro generation has flexibility to vary output from hour to hour, one would expect the hydro operators to change operating behavior to reflect the new market conditions and capitalize on high-priced hours. To the extent that this can occur, actual benefits will be higher than simulated benefits.

3.4.3 Change in Generation Patterns

Table 5 shows the levels of generation in the With RTO and Without RTO cases for each region. This table also demonstrates that the total generation on the system equals the

[33] In such a system, the "value" of the congestion is deemed to be equal to the product of (1) the value of a constrained path and (2) the flow of energy across the path.

[34] To understand the source of the system congestion savings beyond the fuel cost savings, consider the following example. Assume that loads and generators are attempting to use a 1000MW transmission path. If 1001MW of flow requests use of the path, congestion is created and 1MW of redispatch is required to maintain the path within limits. Assume it costs $10 in redispatch cost to alleviate the 1 MW because the fuel cost to alleviate the constraint was $10. In a locational marginal-price system the value of the congestion would be $10 X 1001 MW of users on the path, or $10,010. This is the marginal value of the path. Assume an RTO is implemented in this simple example, and a more efficient generator is able to alleviate the 1 MW of congestion, resulting in a redispatch cost of only $9. In this case the marginal value of the constrained path is $9,009. Applying the concepts of the Energy Impact Analysis to this example would say that the operating cost savings was $1, but reduction in the value of congestion was roughly $1000; loads and generators would have paid $1000 less to use the path in the With RTO case.

[35] If the marginal value of congestion were valued explicitly today, the great majority of the congestion costs would be borne by the Transmission Owners (TOs). Moving to the RTO structure in this framework would result in a transfer of $171 million cost away from the TOs (or possibly transmission rights holders in an RTO framework) and to the loads and generators in the With RTO case.

total load including the pump storage load. It is important to make sure that the energy balance is met, and if the same market clearing prices were used for all buses then there would be no transmission rent or difference in transmission rent.

Table 5: Generation Output in Base Cases

Generation and Demand Balance - Base Cases					
	Generation (GWh)			Demand (GWh)	
Sub-Region	Without	With	Demand	PS Demand Without	PS Demand With
ALBERTA	57557	57362	57278		
BRITCOL	58452	55996	63478		
CA ISO	290232	285498	297923	3,789	3,764
Rocky Mtn	41870	39841	55203		
RTO West	278519	286672	281203		
W Connect	136837	137786	103659	923	635
Total	863467	863154	858744	4,722	4,410
Net after PS	858745	858744			

Table 6 shows the impacts of implementing the RTO on the mix of generation output, as determined in the Energy Impact Analysis. There is a net increase in generation in the RTO West region, mainly from low-cost units, such as coal units, which displace more expensive units (such as combustion turbines and steam gas) in California, the Southwest, and British Columbia. Note the lower generation in British Columbia, which means higher imports from the northwest and Alberta, and lower production cost since the expensive steam gas fired units are displaced.

Note that there is a net mismatch in generation of 313 GWh, which is due to change in the pumping load of pump storage units.

Table 6: Impact of RTO on Generation Mix

Difference in Generation by Unit Type: With RTO-Without RTO (GWh)								
Unit		Region						
Type	Legend	Alberta	BC Hydro	CA ISO	Rocky Mtn	RTO-W	W Connect	Total
AS	Aluminium Smelter Interruptible Loads	0	1	0	0	(28)	0	(27)
CCg	Combined Cycle Gas	20	0	(956)	(1053)	2638	2505	3154
CCgo	Combined Cycle Gas/Oil	0	0	18	0	165	27	210
CCog	Combined Cycle Oil/Gas	0	0	0	0	0	8	8
CG	Co-Generation	2	91	0	114	0	1	209
CTg	Combustion Turbine Gas	(48)	(293)	(978)	(902)	227	(464)	(2457)
CTgo	Combustion Turbine Gas/Oil	0	0	(64)	33	270	0	239
CTo	Combustion Turbine Oil	0	0	0	0	0	0	0
DD	Dispatchable Demand	0	0	(1)	(0)	(1)	(0)	(1)
GEO	Geothermal	0	0	5	0	5	0	10
GTg	Turbine Gas	(6)	0	(272)	10	(30)	0	(298)
GTgk	Turbine Gas/Kerosene	0	0	0	0	0	0	0
GTgo	Turbine Gas/Oil	0	0	0	0	180	0	180
GTk	Turbine Kerosene	0	0	0	0	0	0	0
GTo	Turbine Oil	0	0	0	0	(3)	0	(3)
GTog	Turbine Oil/Gas	0	0	0	0	0	0	0
HRM	Hourly Modifier: Hydro or DC Export	0	0	0	0	(11)	0	(11)
ICgo	Internal Combustion Engine Gas/Oil	0	0	0	0	(0)	0	(0)
ICo	Internal Combustion Engine Oil	0	0	0	0	(0)	0	(0)
NU	Nuclear	0	0	0	0	0	0	0
OTn	Other Types - Non-specified Fuel	1	0	(0)	0	900	0	901
PND	Pondage or Conventional Hydro	0	(0)	(0)	0	0	0	(0)
PSH	Pumped Storage	0	0	(18)	(13)	0	(187)	(217)
PUR	Purchase: DC Import	(162)	0	0	(317)	0	(1445)	(1923)
RET	Retired Unit	0	0	0	0	0	0	0
SOL	Solar	0	0	0	0	0	0	0
STc	Steam Turbine Coal	(3)	0	215	181	3948	746	5086
STcg	Steam Turbine Coal/Gas	0	0	3	(85)	0	(322)	(404)
STco	Steam Turbine Coal/Oil	0	0	2	3	52	94	150
STg	Steam Turbine Gas	0	(2256)	(669)	0	(25)	0	(2950)
STgo	Steam Turbine Gas/Oil	0	0	(2019)	0	(217)	(15)	(2250)
STog	Steam Turbine Oil/Gas	0	0	0	0	0	0	0
STr	Steam Turbine Refuse	0	0	(0)	0	82	0	82
WND	Wind	0	0	0	0	0	0	0
Total		(196)	(2456)	(4734)	(2029)	8153	949	(313)

3.4.4 Average Energy Price Change with RTO West

The base case results show that average annual market clearing prices[36] go down in most load areas in the northwest with the implementation of RTO West, on the order of 10% to 15%, as shown in Table 7. Prices decrease in all regions except Montana, where removal of relatively high company wheeling rates causes an increased flow of higher-priced resources into the region.

Alberta energy prices go down, but there is minimal net impact because Alberta's connection to the WSCC is radial and Alberta is not participating in any RTO. British Columbia energy prices go down as well, but because hydro represents most of generation in BC and the hydro schedule is the same in both the With- and Without RTO cases, the benefits are not significant. Similarly, California prices go down, but the net

[36] The market clearing prices represent the marginal value of the marginal MW produced or consumed at a given location.

impact is small because there are not significant changes between the With RTO and Without RTO cases for California.

Table 7: Average Annual Energy Prices Comparison

Annual Average Energy Price (Real 2000$/MWh)				
Area	Region	Without RTO	With RTO	% Change
BC Hydro + W Kooteny	RTO-West	35.80	34.41	(3.89)
Avista Corp	RTO-West	35.50	29.70	(16.34)
Bonneville Power Admin	RTO-West	34.82	29.75	(14.57)
Chelan Douglas Grant PUD	RTO-West	34.18	29.73	(13.01)
Idaho Power Company	RTO-West	30.30	28.93	(4.53)
Montana Power Company	RTO-West	25.24	26.82	6.27
Nevada Power Company	RTO-West	33.75	30.38	(9.99)
Pacificorp East	RTO-West	30.16	27.46	(8.94)
Pacificorp West	RTO-West	32.73	29.68	(9.33)
Portland General Electric	RTO-West	33.42	29.73	(11.05)
Puget Sound Energy	RTO-West	35.60	29.77	(16.39)
Seattle City Light	RTO-West	34.82	29.75	(14.56)
Sierra Pacific Power	RTO-West	40.99	33.21	(18.97)
Tacoma Public Utilities	RTO-West	34.42	29.75	(13.56)
Alberta Power	ALBERTA	23.98	23.81	(0.69)
LA Dept of Water & Power	CA ISO	34.39	30.99	(9.87)
Pacific Gas & Electric	CA ISO	32.88	31.32	(4.76)
San Diego Gas & Electric	CA ISO	32.20	30.97	(3.83)
Southern California Edison	CA ISO	32.93	31.41	(4.61)
Public Service of Colora	Rocky Mtn	32.66	25.72	(21.23)
WAPA Colorado-Missouri	Rocky Mtn	26.75	25.76	(3.73)
WAPA Upper Missouri	Rocky Mtn	27.59	24.56	(10.99)
Arizona Public Service	WConnect	31.17	27.77	(10.93)
El Paso Electric	WConnect	36.17	30.63	(15.32)
Imperial Irrigation Dist	WConnect	30.69	28.71	(6.44)
Public Service New Mexico	WConnect	33.16	27.80	(16.14)
Salt River Project	WConnect	31.12	27.68	(11.06)
Tucson Electric Power	WConnect	31.14	27.41	(11.96)
WAPA Lower Colorado	WConnect	31.11	27.42	(11.85)

3.4.5 Monthly Energy Price With RTO

Table 8 shows the average monthly prices in each region in the With RTO case. These prices are the simple average of hourly load-weighted zonal prices over each month. The energy prices vary by location and time, and prices are higher in constrained areas during their load peak periods (such as British Columbia in the winter, and SDG&E in the summer).

Table 8: Monthly Energy Prices With RTO

Monthly Simple Average of Hourly Load-Weighted Average Energy Prices ($/MWh)														
Area	Region	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
Alberta Power	Alberta	31	25	22	21	24	22	22	18	20	24	24	23	23
BC Hydro + W Kooteny	BC Hydro	53	37	33	29	33	31	31	25	30	37	38	37	35
LA Dept of Water & Power	CA ISO	30	32	30	27	28	30	33	31	31	33	34	33	31
Pacific Gas & Electric	CA ISO	30	32	30	28	29	30	34	31	32	34	34	33	31
San Diego Gas & Electric	CA ISO	30	32	30	28	28	30	33	31	31	33	33	32	31
Southern California Edis	CA ISO	31	32	30	30	30	30	33	31	31	33	33	33	31
Public Service of Colora	Rocky Mtn	26	26	25	23	23	25	27	25	25	28	30	28	26
WAPA Colorado-Missouri	Rocky Mtn	26	27	25	23	23	25	27	25	25	28	30	28	26
WAPA Upper Missouri	Rocky Mtn	26	26	25	22	21	18	24	23	23	27	31	30	25
Avista Corp	RTO W	31	31	29	24	24	24	30	27	28	36	37	35	30
Bonneville Power Adminis	RTO W	31	31	29	24	24	25	30	27	28	36	37	35	30
Chelan Douglas Grant PUD	RTO W	31	31	29	24	24	25	30	27	28	36	37	34	30
Idaho Power Company	RTO W	29	30	28	24	25	27	30	27	27	32	35	33	29
Montana Power Company	RTO W	27	28	26	24	24	20	27	25	26	29	33	32	27
Nevada Power Company	RTO W	29	31	29	27	28	31	34	30	31	32	32	30	30
Pacificorp East	RTO W	27	29	27	24	25	27	28	26	26	29	31	29	27
Pacificorp West	RTO W	31	31	28	24	24	25	30	27	28	36	37	34	30
Portland General Electri	RTO W	31	31	29	24	24	25	30	27	28	36	37	34	30
Puget Sound Energy	RTO W	31	31	29	24	25	25	30	27	28	36	37	35	30
Seattle City Light	RTO W	31	31	29	24	25	25	30	27	28	36	37	34	30
Sierra Pacific Power	RTO W	36	33	30	26	28	30	35	31	33	38	39	38	33
Tacoma Public Utilities	RTO W	31	31	29	24	25	25	30	27	28	36	37	35	30
Arizona Public Service C	W Connect	27	29	27	24	25	27	30	27	28	30	30	28	28
El Paso Electric	W Connect	32	29	27	25	29	33	34	31	31	31	32	33	31
Imperial Irrigation Dist	W Connect	28	29	27	25	27	28	32	29	29	30	31	29	29
Public Service New Mexic	W Connect	27	28	27	24	25	28	30	27	28	29	30	29	28
Salt River Project	W Connect	27	29	27	24	25	27	30	27	28	30	30	28	28
Tucson Electric Power	W Connect	26	29	27	24	25	27	30	27	28	29	30	28	27
WAPA Lower Colorado	W Connect	27	28	27	24	25	27	30	27	28	29	30	28	27

Table 9 shows the load-weighted average monthly prices in each region in the With RTO case. These prices are the zonal load-weighted average of hourly load-weighted zonal prices over each month. These prices would be more reflective of energy cost when multiplied by the monthly energy consumption of each region. The pattern is similar to that in the preceding table.

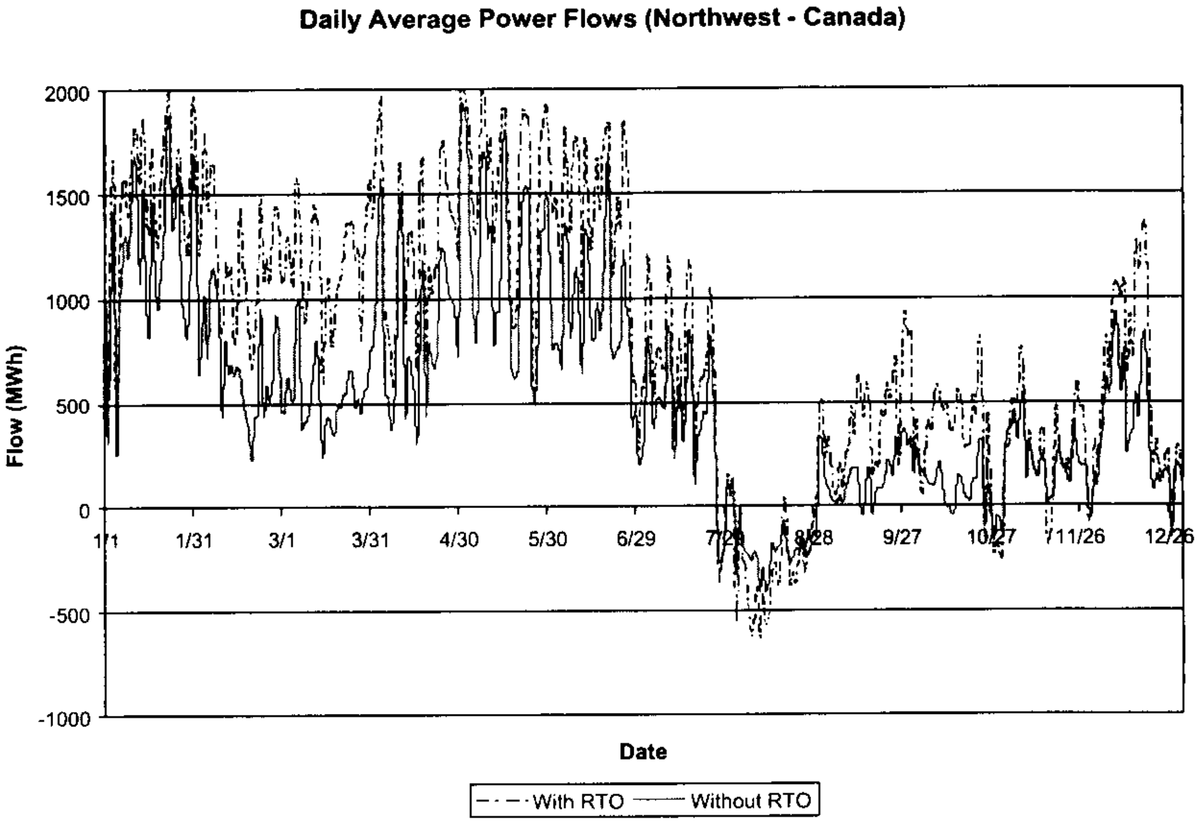
Table 9: Monthly Load-Weighted Average Energy Prices—With RTO

Monthly Load-Weighted Average of Hourly Load-Weighted Average Energy Prices ($/MWh)														
Area	Region	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
Alberta Power	Alberta	32	26	22	22	24	23	22	19	20	24	25	24	24
BC Hydro + W Kooteny	BC Hydro	56	37	33	29	34	31	32	26	30	38	39	37	36
LA Dept of Water & Power	CA ISO	30	32	30	28	29	31	34	31	32	33	34	33	32
Pacific Gas & Electric	CA ISO	30	33	30	28	30	31	35	32	33	34	35	34	32
San Diego Gas & Electric	CA ISO	30	33	30	28	29	31	35	32	32	34	34	33	32
Southern California Edis	CA ISO	31	32	30	30	30	31	35	32	32	34	34	33	32
Public Service of Colora	Rocky Mtn	26	27	25	23	24	26	28	26	26	28	30	29	26
WAPA Colorado-Missouri	Rocky Mtn	26	27	25	23	23	25	28	25	25	28	30	29	26
WAPA Upper Missouri	Rocky Mtn	26	26	25	22	22	19	25	24	24	28	31	31	25
Avista Corp	RTO W	31	31	29	24	24	24	30	27	29	37	37	35	30
Bonneville Power Adminis	RTO W	31	31	29	24	25	25	30	27	29	37	37	35	30
Chelan Douglas Grant PUD	RTO W	31	31	29	24	25	25	30	27	29	36	37	35	30
Idaho Power Company	RTO W	29	30	28	25	25	27	30	27	28	33	35	33	29
Montana Power Company	RTO W	27	28	27	24	24	20	28	26	26	30	33	32	27
Nevada Power Company	RTO W	29	31	29	27	29	32	36	32	32	33	33	30	31
Pacificorp East	RTO W	27	29	28	25	26	28	29	27	27	30	32	30	28
Pacificorp West	RTO W	31	31	29	25	25	25	31	28	29	36	37	35	30
Portland General Electri	RTO W	31	31	29	25	25	25	31	27	29	37	37	35	30
Puget Sound Energy	RTO W	31	31	29	25	25	25	30	27	29	37	37	35	30
Seattle City Light	RTO W	31	31	29	25	25	25	30	27	29	37	37	35	30
Sierra Pacific Power	RTO W	36	33	30	26	28	30	35	31	34	38	39	38	33
Tacoma Public Utilities	RTO W	31	31	29	24	25	25	30	27	29	37	37	35	30
Arizona Public Service C	W Connect	27	29	27	25	26	28	31	28	29	30	30	29	28
El Paso Electric	W Connect	32	29	27	25	29	33	34	31	31	31	32	33	31
Imperial Irrigation Dist	W Connect	28	29	27	26	27	29	32	29	30	31	31	30	29
Public Service New Mexic	W Connect	27	28	27	24	26	28	30	28	28	30	30	29	28
Salt River Project	W Connect	27	29	27	25	26	28	31	28	29	30	30	29	28
Tucson Electric Power	W Connect	26	29	27	25	26	28	31	28	29	30	30	29	28
WAPA Lower Colorado	W Connect	27	30	28	26	27	30	33	29	30	31	32	30	29

3.4.6 Comparing With RTO and Without RTO Power Flows

Figure 2 shows the hourly flows from the U.S. to Canada (positive) starting in January, in the With RTO and Without RTO West cases. The figure demonstrates how the economic transfers (power flows) increase among regions with the introduction of RTO West.

Figure 2: Intertie Flows With and Without the RTO



3.4.7 Binding Transmission Constraints

The more efficient dispatch causes higher congestion on some paths and lower congestion on other paths (because it is utilizing the transmission system more efficiently without the contractual constraints). Table 10 shows the change in the number of hours in which significant paths are shown by the Energy Impact Analysis to be binding.

Table 10: Impact of RTO West on Individual Constraints

	% of Hours Binding	
Constraint	**Without RTO**	**With RTO**
Pavant/InterMt-Gonder Actual	99%	75%
EDMONTON-CALGARY LIMIT	96%	96%
Eagle Mountain-Blythe 161 k	90%	91%
Montana to Northwest MIN	74%	75%
Northwest-Canada MIN	46%	67%
Pacificorp/PG&E South	63%	7%
TOT 2C	58%	44%
PG&E - SPP	58%	15%
NM1 Actual	15%	50%
Montana Southeast Tie MIN	35%	48%
ALTURAS	22%	40%
Idaho to Northwest MIN	26%	30%
Intermountain - Mona 345	26%	26%
South of San Onofre	16%	9%
Montana to Northwest MEAN	11%	15%
Inyo-Control 115 kV	13%	15%
Idaho-Sierra	5%	11%
BLGS PHA 230-YELOWTLP 230	8%	10%
INYOKERN-KRAMER 115	10%	10%
Billings-Yellowtail	9%	7%
Northwest-Canada	3%	9%
BIGGRASS 161-DILLON S 161	4%	8%
Northern - Southern Californ	7%	8%
Coranado-Silverking-Kyrene	1%	7%
COI MIN	6%	4%
TOT 2A Actual	0%	5%
Montana Southeast Tie	0%	5%
BOUNDARY 230-NLYPHS 230- 1	2%	5%
Path C Actual MIN	2%	4%
Midway - Los Banos	4%	2%
WOR Northern System Actual	1%	4%
Northwest-Canada MEAN	0%	2%
TOT 1A Actual	2%	1%
TOT 4B Actual	2%	2%
Keeler Allston Tie MIN	1%	1%
MONA 345-BONANZA 345- 1	0%	1%
LUGO 500-VICTORVL	1%	1%
Borah West Actual	0%	1%
TOT 5 Actual	0%	1%
HATWAI 230-LOLO 230 0	1%	1%
Bridger West	0%	1%
Idaho-Northwest 500	0%	1%
West of Borah - Path 15 Wint	1%	0%
TOT 3 Actual	0%	0%

3.5 Sensitivity Runs - Descriptions and Results

TCA was directed to evaluate sensitivity runs of two types:

1. Physical System Modifications
   a. Short Supply Case: Low Water/High Gas Prices
   b. Resource Addition Case: Montana New Entry

2. Benefits Driver Sensitivities
   a. With RTO: Transmission Line Losses Fixed as Without RTO
   b. With RTO: RTO Export Fees Set to Zero
   c. With RTO: Scheduling Limits Fixed as Without RTO
   d. With RTO: Maintenance Schedule Fixed as Without RTO
   e. Operating Reserves (Non AGC) set to zero in both cases, eliminating impact of Operating Reserves on Benefits

3.5.1 Summary of Sensitivity Runs

The sensitivity analyses suggest two primary benefit drivers, which reflect the modeling techniques. The pancaked rates seem to have a strong bearing on benefits; by reinstating pancaked loss charges alone, net benefits dropped by 38% (to $255 million), all of this reduction ($155) comes from reduced congestion rent savings. This sensitivity case was the only case significantly impacting congestion rent savings. Similarly, operating reserves seem to be the only attribute tested that a strong effect on production cost benefits. The efficient allocation of operating reserves also has a strong bearing on total benefits: isolating the impact of operating reserves showed over 60% reduction in production cost savings (from $239 million to $89 million).

The Energy Impact Analysis is relatively insensitive (3% or less impact on total benefits) to other tested attributes, including maintenance scheduling, contract path scheduling limits, and export fees.

From the sensitivity runs, TCA draws the following broad implications:

- Pancaking therefore has a greater impact on the congestion prices across constraints than it does on overall production cost efficiency; and
- The ability to further substitute hydro resources for thermal resources , through further regionalization of operating reserves, offers significant benefits.

Table 11 summarizes the impact of various benefit-driver sensitivities.

Table 11: Summary of Sensitivity Run Results

Savings in $ Millions (2000 Dollars)			
Sensitivity	Impact on Generation Cost Savings	Impact on Congestion Rent Savings	Total Impact
Base Case	239	171	410
Use Low Hydro conditions and High Gas prices in both cases	263	142	405
Change in Savings	24	-29	-5
Use higher New Entry in Montana in both cases	246	150	396
Change in Savings	7	-21	-14
Pancaked Loss Charges in With RTO West Case	241	14	255
Change in Savings	2	-157	-155
Set the export fee to zero in the With RTO Case	239	164	403
Change in Savings	0	-7	-7
Impose Scheduling Limits on Paths in with RTO West Case	238	160	398
Change in Savings	-1	-11	-12
Use same Maint. Sch. for Gen. units in both cases	212	196	408
Change in Savings	-27	25	-2
Isolate the impact of Operating Reserves in both cases	89	202	291
Change in Savings	-150	31	-119

3.5.2 Low Water/High Gas Prices

In this sensitivity, the following were changed in the With RTO and Without RTO cases:

- The hydro fixed schedule was changed to correspond to a dry hydro year as provided by RTO West.
- Natural Gas price forecast was changed to correspond to EIA high gas price forecast (AEO 2001).

Summary of Benefits

The results summarized in Table 12 show that net benefits would decrease by $5 million, due to greater fuel savings of $24 million and reduced transmission rent savings of $29 million compared to the base case as shown in Table 11[37].

Table 12: Low Water/High Gas Price Results

Summary of Benefits ($M)- Difference Between With and Without RTO - Low Water/High Gas								
	A	B	C	D	E	F	G	H
Sub-Region	Load Energy Payment	Uplift Payment	Spinning Reserve Payment	Total Load Payment A+B+C	Generation Cost	Generator Energy Revenue	Generator Net Revenue B+C+F-E	Net Impact G-D
ALBERTA	(59)	0	0	(58)	(4)	(50)	(46)	13
BRITCOL	(93)	(2)	(16)	(111)	(84)	(171)	(106)	5
CA ISO	(1,044)	22	(120)	(1,142)	(108)	(1,170)	(1,159)	(17)
Rocky Mtn	(471)	(2)	(107)	(580)	(139)	(444)	(413)	167
Rest of RTO West	(943)	3	(340)	(1,280)	102	(641)	(1,081)	199
W Connect	(591)	(3)	(132)	(726)	(30)	(583)	(688)	38
Total	(3,201)	18	(714)	(3,898)	(263)	(3,060)	(3,493)	405

3.5.3 Montana New Entry

The following generation units were added in Montana in both With RTO and Without RTO cases (on-line date is 2002–2003):

- MT First MW: 280 MW gas-fired combined cycle unit at Great Falls
- Hardin Generator: 100 MW coal-fired steam unit at Hardin Auto
- MT Wind harness—3 sites
- 50 MW, near Judith Gap
- 50 MW, near Cut Bank
- 50 MW, near Adel-Seiben

Summary of Benefits

The results summarized in Table 13 show that the net benefits decrease by $14 million. Although the fuel cost savings are higher by $7 million, the transmission rent savings are lower by $21 million.

[37] Additional information on annual average locational energy prices are included in Attachment 3.

Table 13: MT New Entry Results

Summary of Benefits ($M)- Difference Between With and Without RTO - MT New Entry								
	A	B	C	D	E	F	G	H
Sub-Region	Load Energy Payment	Uplift Payment	Spinning Reserve Payment	Total Load Payment A+B+C	Generation Cost	Generator Energy Revenue	Generator Net Revenue B+C+F-E	Net Impact G-D
ALBERTA	(35)	0	(1)	(36)	(6)	(35)	(30)	6
BRITCOL	(40)	(2)	(1)	(44)	(91)	(119)	(32)	12
CA ISO	(479)	6	(44)	(517)	(155)	(636)	(519)	(2)
Rocky Mtn	(435)	(1)	(80)	(516)	(122)	(459)	(418)	98
Rest of RTO West	(965)	0	(196)	(1,161)	137	(570)	(902)	258
W Connect	(415)	(1)	(116)	(533)	(8)	(399)	(508)	25
Total	(2,369)	2	(438)	(2,806)	(246)	(2,218)	(2,409)	396

It is interesting that the net savings are lower in this case. As shown in Table 15, the energy prices in Montana are much lower (by 9%) than in the base case, for both the With RTO and Without RTO cases. The additional generation units created excess capacity in Montana that increased congestion out of Montana and lowered the locational energy prices in Montana, as shown in Table 14. Thus, the system is more efficient with the additional units, and there are fewer savings from implementing the RTO. This is a very important observation: the higher the excess generation levels throughout the system, the lower the savings or the benefits of establishing an RTO.

Table 14: Change in Transmission Congestion in Montana

	Base Case		MT New Entry		Change	
Line Name	With	Without	With	Without	With	Without
Montana to Northwest MEAN	1333	988	2408	1903	81%	93%
Montana to Northwest MIN	6553	6458	6973	6818	6%	6%
Montana Southeast Tie MIN	4197	3117	5519	3274	31%	5%
Billings-Yellowtail	609	794	140	582	-77%	-27%
BLGS PHA 230-YELOWTLP 230	913	690	748	668	-18%	-3%

Table 15: MT New Entry—Change in Prices

Annual Average Energy Price (Real 2000$/MWh)				
Area	Region	Without RTO	With RTO	% Change
BC Hydro + W Kooteny	RTO-West	35.19	34.43	(2.15)
Avista Corp	RTO-West	34.57	29.42	(14.91)
Bonneville Power Admin	RTO-West	33.94	29.45	(13.22)
Chelan Douglas Grant PUD	RTO-West	33.44	29.42	(12.01)
Idaho Power Company	RTO-West	29.11	28.39	(2.48)
Montana Power Company	RTO-West	23.04	24.20	5.06
Nevada Power Company	RTO-West	32.68	30.05	(8.03)
Pacificorp East	RTO-West	28.94	26.87	(7.14)
Pacificorp West	RTO-West	31.68	29.33	(7.43)
Portland General Electric	RTO-West	31.52	29.41	(6.70)
Puget Sound Energy	RTO-West	34.77	29.48	(15.21)
Seattle City Light	RTO-West	34.01	29.46	(13.38)
Sierra Pacific Power	RTO-West	40.47	32.99	(18.50)
Tacoma Public Utilities	RTO-West	33.59	29.46	(12.30)
Alberta Power	ALBERTA	23.62	23.06	(2.40)
LA Dept of Water & Power	CA ISO	33.84	30.80	(8.99)
Pacific Gas & Electric	CA ISO	32.66	31.19	(4.49)
San Diego Gas & Electric	CA ISO	31.91	30.79	(3.49)
Southern California Edison	CA ISO	32.65	31.23	(4.33)
Public Service of Colora	Rocky Mtn	34.95	25.26	(27.73)
WAPA Colorado-Missouri	Rocky Mtn	29.13	25.19	(13.53)
WAPA Upper Missouri	Rocky Mtn	28.48	22.25	(21.89)
Arizona Public Service	WConnect	30.83	27.59	(10.49)
El Paso Electric	WConnect	36.91	30.47	(17.45)
Imperial Irrigation Dist	WConnect	30.24	28.56	(5.56)
Public Service New Mexico	WConnect	32.60	27.54	(15.53)
Salt River Project	WConnect	30.78	27.51	(10.62)
Tucson Electric Power	WConnect	30.50	27.23	(10.73)
WAPA Lower Colorado	WConnect	31.03	27.22	(12.28)

3.5.4 Transmission Line Losses

The pancaked loss charges were changed to be included in both the With and Without RTO cases, instead of the With RTO case only, as shown in Table 16.

Table 16: Pancaked Loss Factors Case—Loss Factors

Loss Factors

Region / Utility	*With & Without RTO*	*Region / Utility*	*With & Without RTO*	*Region / Utility*	*With & Without RTO*
RTO West		California		WestConnect	
Avista Corp.	3.00%	PG&E - high voltage only	3.0%	Arizona Public Service	2.50%
Idaho Power Company	3.60%	PG&E - low voltage		El Paso Electric	3.00%
Montana Power Co.	4.00%	SCE - high voltage only		Public Service of New Mexico	3.00%
PacifiCorp	4.48%	SCE - low voltage		Salt River Project	2.30%
Portland General Electric	1.60%	SDG&E - high voltage only		Texas-New Mexico Power	3.34%
Puget Sound Energy	2.70%	SDG&E - low voltage		Tucson Electric Power	3.30%
Sierra Pacific Resources		California - Oregon Border (COB)		WAPA Lower Colorado	3.00%
Zone A (Sierra Pacific Power)	2.34%	Palo Verde intertie		WAPA Rocky Mountain	5.50%
Zone B (Nevada Power)	1.32%	Nevada - Oregon Border (NOB)		WAPA Upper Missouri	4.00%
Bonneville Power Administration		Mead intertie (MEAD - WALC)		Imperial Irrigation District	3.0%
Network	1.90%	Victorville intertie			
Southern intertie	3.00%	Sylmar AC			
Montana intertie	3.00%	LADWP	4.8%		
BC Hydro	6.05%				
Alberta (included in wheeling charge)	-				

Notes:

BPA loss factor applies to wheel-outs and wheel-ins. When wheeling power over an intertie, the intertie rate is added to the network rate.
California and WestConnect losses apply to wheel-outs, except for Imperial Irrigation, which applies to wheel-ins and wheel-outs.

Summary of Benefits

The results summarized in Table 17 show that fuel cost savings increase by $2 million while transmission rent savings decrease by $157 million. Note that the increase in fuel savings is due to lower generation from thermal units.

As a result of eliminating pancaked losses in this sensitivity, the pump storage units are running less often, reducing pumped storage demand by around 13 GWh. This results in lower generation cost and the higher fuel savings.

Table 17: Pancaked Losses Results

Summary of Benefits ($M)- Difference Between With and Without RTO - Pancaked Loss Charges								
	A	B	C	D	E	F	G	H
Sub-Region	Load Energy Payment	Uplift Payment	Spinning Reserve Payment	Total Load Payment A+B+C	Generation Cost	Generator Energy Revenue	Generator Net Revenue B+C+F-E	Net Impact G-D
ALBERTA	(53)	0	(2)	(54)	(8)	(53)	(46)	8
BRITCOL	(56)	(2)	(3)	(61)	(87)	(134)	(51)	9
CA ISO	(548)	15	(54)	(586)	(184)	(739)	(594)	(8)
Rocky Mtn	(251)	(0)	(76)	(327)	(62)	(250)	(264)	63
Rest of RTO West	(1,163)	1	(214)	(1,375)	121	(857)	(1,190)	185
W Connect	(344)	(2)	(106)	(452)	(20)	(365)	(454)	(2)
Total	(2,413)	14	(455)	(2,854)	(241)	(2,398)	(2,599)	255

3.5.5 Export Fees

In this sensitivity, TCA assumed that there is no export fee for energy flowing out of the RTO West region (in the With RTO case).

Summary of Benefits

The results summarized in Table 18 show that net benefits would decrease by $7 million, mainly due lower transmission rent savings. Lowering wheeling rates from $3.80/MWh to $0/MWh has small impact on system wide operation.

Table 18: Zero RTO West Export Fee Results

Summary of Benefits ($M)- Difference Between With and Without RTO - Export Fee								
	A	B	C	D	E	F	G	H
Sub-Region	Load Energy Payment	Uplift Payment	Spinning Reserve Payment	Total Load Payment A+B+C	Generation Cost	Generator Energy Revenue	Generator Net Revenue B+C+F-E	Net Impact G-D
ALBERTA	(18)	0	(0)	(18)	(3)	(18)	(14)	4
BRITCOL	12	(2)	(2)	8	(83)	(68)	11	3
CA ISO	(575)	18	(54)	(611)	(196)	(778)	(618)	(6)
Rocky Mtn	(242)	0	(77)	(319)	(51)	(228)	(254)	65
Rest of RTO West	(798)	0	(201)	(998)	134	(365)	(700)	298
W Connect	(419)	(1)	(111)	(531)	(40)	(420)	(493)	39
Total	(2,041)	15	(444)	(2,471)	(239)	(1,878)	(2,068)	403

Table 19: Zero RTO Export Fee Energy Prices

Annual Average Energy Price (Real 2000$/MWh)				
Area	Region	Without RTO	With RTO	% Change
BC Hydro + W Kooteny	RTO-West	35.80	35.87	0.20
Avista Corp	RTO-West	35.50	31.20	(12.13)
Bonneville Power Admin	RTO-West	34.82	31.27	(10.20)
Chelan Douglas Grant PUD	RTO-West	34.18	31.26	(8.52)
Idaho Power Company	RTO-West	30.30	30.25	(0.19)
Montana Power Company	RTO-West	25.24	28.06	11.18
Nevada Power Company	RTO-West	33.75	30.98	(8.23)
Pacificorp East	RTO-West	30.16	28.17	(6.61)
Pacificorp West	RTO-West	32.73	31.22	(4.61)
Portland General Electric	RTO-West	33.42	31.28	(6.42)
Puget Sound Energy	RTO-West	35.60	31.28	(12.13)
Seattle City Light	RTO-West	34.82	31.27	(10.18)
Sierra Pacific Power	RTO-West	40.99	34.47	(15.91)
Tacoma Public Utilities	RTO-West	34.42	31.27	(9.14)
Alberta Power	ALBERTA	23.98	23.72	(1.10)
LA Dept of Water & Power	CA ISO	34.39	30.97	(9.94)
Pacific Gas & Electric	CA ISO	32.88	30.99	(5.76)
San Diego Gas & Electric	CA ISO	32.20	30.96	(3.87)
Southern California Edison	CA ISO	32.93	31.37	(4.74)
Public Service of Colora	Rocky Mtn	32.66	26.14	(19.95)
WAPA Colorado-Missouri	Rocky Mtn	26.75	26.24	(1.93)
WAPA Upper Missouri	Rocky Mtn	27.59	25.63	(7.10)
Arizona Public Service	WConnect	31.17	27.85	(10.67)
El Paso Electric	WConnect	36.17	30.66	(15.23)
Imperial Irrigation Dist	WConnect	30.69	28.74	(6.34)
Public Service New Mexico	WConnect	33.16	27.86	(15.97)
Salt River Project	WConnect	31.12	27.76	(10.80)
Tucson Electric Power	WConnect	31.14	27.51	(11.63)
WAPA Lower Colorado	WConnect	31.11	27.56	(11.41)

3.5.6 Scheduling Limits

Scheduling limits were imposed on the With RTO case, but there were assumed to be no wheeling charges associated with contract path flows.

Summary of Benefits

The results summarized in Table 20 show that the contract path scheduling limits have small impact on the dispatch and prices. This happens because MAPS reschedules the flows on alternative paths at no cost (zero wheeling charges were assumed on all paths) when that path reaches its limit. The net benefits decrease by $12 million, due to lower transmission rent savings of $11 million, and lower fuel savings of $1 million.

Table 20: RTO With Scheduling Limits Results

Summary of Benefits ($M)- Difference Between With and Without RTO - Scheduling Limits								
	A	B	C	D	E	F	G	H
Sub-Region	Load Energy Payment	Uplift Payment	Spinning Reserve Payment	Total Load Payment A+B+C	Generation Cost	Generator Energy Revenue	Generator Net Revenue B+C+F-E	Net Impact G-D
ALBERTA	(14)	0	(0)	(14)	(4)	(13)	(9)	5
BRITCOL	(82)	(2)	(3)	(87)	(88)	(159)	(75)	11
CA ISO	(525)	14	(50)	(560)	(175)	(712)	(572)	(12)
Rocky Mtn	(270)	0	(77)	(347)	(60)	(259)	(276)	72
Rest of RTO West	(1,164)	1	(209)	(1,372)	125	(744)	(1,078)	295
W Connect	(424)	(1)	(110)	(536)	(36)	(432)	(508)	28
Total	(2,479)	12	(450)	(2,917)	(238)	(2,319)	(2,519)	398

3.5.7 Maintenance Schedule

For this sensitivity test, instead of optimizing the maintenance schedule of generation units according to regional loads in the With RTO West case, TCA used the same maintenance schedule in the With RTO case as MAPS determined for the Without RTO case.

Summary of Benefits

The results summarized in Table 21 show a minor reduction of $2 million in net benefits for this case, resulting from additional expenditures for fuel of $27 million and reduction in transmission rents of $25 million.

Table 21: RTO With Control Area Maintenance Schedule Results

Summary of Benefits ($M)- Difference Between With and Without RTO - Maintenance Schedule								
	A	B	C	D	E	F	G	H
Sub-Region	Load Energy Payment	Uplift Payment	Spinning Reserve Payment	Total Load Payment A+B+C	Generation Cost	Generator Energy Revenue	Generator Net Revenue B+C+F-E	Net Impact G-D
ALBERTA	(55)	(0)	(2)	(57)	(8)	(54)	(48)	9
BRITCOL	(70)	(1)	(3)	(75)	(75)	(130)	(59)	16
CA ISO	(515)	11	(53)	(557)	(163)	(687)	(566)	(10)
Rocky Mtn	(263)	0	(77)	(340)	(62)	(251)	(266)	74
Rest of RTO West	(1,105)	1	(209)	(1,313)	127	(709)	(1,045)	268
W Connect	(425)	(1)	(109)	(535)	(31)	(405)	(484)	50
Total	(2,432)	9	(453)	(2,876)	(212)	(2,236)	(2,469)	408

3.5.8 Operating Reserves

In this sensitivity, our objective was to isolate the impact of more efficient allocation of operating reserves from the impact of other variables. The difference in benefits in this case compared to the base case can be attributed to the change in operating reserves allocation. TCA achieved this by excluding the impact of operating reserves in both the

With RTO and Without RTO cases and calculating the benefits of other features of RTO West.

Summary of Benefits

The results summarized in Table 22 show that most of the fuel savings are eliminated by ignoring the impact of operating reserves.

Table 22: Operating Reserve Sensitivity Results

Summary of Benefits ($M)- Difference Between With and Without RTO - Operating Reserves								
	A	B	C	D	E	F	G	H
Sub-Region	Load Energy Payment	Uplift Payment	Spinning Reserve Payment	Total Load Payment A+B+C	Generation Cost	Generator Energy Revenue	Generator Net Revenue B+C+F-E	Net Impact G-D
ALBERTA	(9)	0	-	(9)	(3)	(9)	(6)	3
BRITCOL	1	(4)	-	(3)	(76)	(61)	12	14
CA ISO	1	(7)	-	(6)	9	(2)	(18)	(12)
Rocky Mtn	(69)	0	-	(69)	(44)	(106)	(62)	7
Rest of RTO West	(455)	0	-	(455)	79	(157)	(235)	220
W Connect	(217)	(1)	-	(218)	(53)	(211)	(159)	59
Total	(747)	(12)	-	(759)	(89)	(546)	(469)	291

4 Other Quantified RTO Impacts - Benchmarking

This section describes the quantitative benchmarking analyses. TCA gathered information from industry sources in several areas:

- Startup and operating costs for RTOs,[38]
- Startup and operating costs of exchanges,
- Costs of performing a schedule coordinator role, and
- Monetary valuation of impacts of unplanned outages (loss of load).

Each of these areas is addressed below.

4.1 Startup and Operating Costs for RTOs

The October 2000 "RTO West Potential Benefits and Costs" report estimated the RTO West expected startup costs at $82 million and the annual operating costs at $50 million. This estimate was based on the October 2000 study group's best estimate of the levels of staffing and startup costs anticipated.

TCA collected data related to costs to develop and maintain ISOs/RTOs in North America.[39] This effort was intended to provide insights into the *actual* operating costs of similar organizations in the United States and Canada. The cost data were collected from a variety of sources, primarily publications from the respective organizations.

Table 23 summarizes the data collected for each of the ISOs and RTOs in North America.[40] The table shows startup and annual operating costs where available. In all

[38] "RTO" is used in this Section and in Section 5 to represent the broad set of RTO organizations, including ISOs.

[39] Within this section the terms ISO and RTO are used interchangeably to represent, except where noted, functionality on the scale expected within the RTO West.

[40] Notes/Sources:

A. All values in $US.
B. Direct comparisons across regions must be undertaken with care. Some shared regional functions and cost responsibilities are handled outside of ISO cost structure.
C. Some start-up costs not reflected or associated with previous tight pool structure and cost recovery.
D. Cost values actual or projected for 2000 or 2001, except where noted.
E. New England annual depreciation and interest costs are accounted for outside of the NE-ISO tariff structure.
F. Ontario, PJM, New England, and NY values from Ontario Independent Market Operator (IMO) Business Plan 2001-2003, November 2000.
G. NY ISO transition costs were obtained from the NY ISO Annual Report, 2000.
H. ERCOT values taken from Public Utility Commission of Texas Docket 23320 filings.
I. Alberta values from Transmission Administrator (TA) and Power Pool of Alberta (PP) Annual Review / Report documents for 2000, and Cox Report (see note L), and as provided by EAL professionals.

cases, however, all-in per-megawatt-hour carrying costs (startup and operating costs) have been provided or derived for each ISO/RTO and are shown.

J. Ontario start-up costs based on 1999 - 2001 capital expenditures from the IMO Business Plan 2001-2003, page 32 ($CA 254 Million).

K. ERCOT start-up costs based on 2000 - 2001 capital expenditures as reported in the "Year 2001 ERCOT Fund Summary" in Docket 23320 filing.

L. California numbers are from 2001 and are from "Participant Charges at Electricity Exchanges, Pools and ISOs: Towards a Benchmarking Study," prepared for the Power Pool of Alberta by Paul Cox, December 29, 2000, and revised May 9, 2001.

M. PJM is represented in several configurations in the table, and all configurations are included in the weighted averages. Since the costs of these configurations span the range of other ISO costs, this factor is not expected to materially bias the average.

Table 23: Startup and Operating Costs of ISOs/RTOs

	Annual O&M Costs ($ million)	Annual Amortized Depreciation and Interest Costs ($ million)	Total Annual Revenue Requirement with Debt & Interest ($ million)	Annual Energy (TWh)	Unit O&M Costs ($/MWh)	Unit Revenue Requirement ($/MWh)	Peak Demand 2000 (MW)	Transmission Miles	# FTE employees	Staffing FTE/TWh	Start-up Costs ($ million)
PJM (2000)	70.2	31.6	101.8	256	0.27	0.40	49,417	8,000	384	1.50	140
PJM without PJM West (2002)			128.9	256		0.50		8,000			
PJM with PJM West (2002)			137.3	314		0.44		13,100			
New York	53.7	6.9	60.6	149	0.36	0.41	30,311	10,800	222	1.49	82
New England	55.7		55.7	122	0.46	0.46	23,300	7,000	323	2.65	55
Calif ISO			228.0	270		0.84	45,990	25,526	544	2.01	
ERCOT	44.6	77.4	122.1	281	0.16	0.44	57,606	37,000	250	0.89	137
Alberta TA and SC	6.3		21.4	54		0.40	7,785	10,540	76	1.41	
Ontario	57.6	28.4	86.0	150	0.39	0.58	23,428	18,000	417	2.79	172
Weighted Average $/MWh RTO Carrying Cost						0.51					
Weighted Average $/MWh RTO Carrying Cost, Without CA ISO						0.45					

Several items should be noted when applying these numbers to the relative net merits of RTO West.

- Numbers should be viewed as "ball park," given, for example, the averaging of dollar values from different years.
- Application of these values to an RTO West valuation requires judgment about the comparable level of effort required for RTO West.
- Various attributes are not distinguished in the preceding table:
  - ISO costs may include upgrades that would have occurred with or without the RTO:
    - Regional upgrades
    - SCADA upgrades
    - Y2k upgrades
  - RTO West costs are direct costs, not adjusted for parallel savings by the TOs or CAOs.
  - RTO West costs do not include the costs of stakeholder participation in the development process.

However, the table shows that the carrying costs of an RTO generally group fairly tightly. With the exception of California, which is broadly believed to have encountered unusually high startup costs, the other RTOs are relatively tightly grouped in a range of \$0.40/MWh to \$0.58/MWh.[41] The weighted average cost of the existing RTOs in North America is approximately \$0.45 to \$0.51, with the lower value representing the case in which California and Alberta are excluded from the mix.

Given the annual energy throughput expected for RTO West[42] in 2004, per-unit costs such as these quoted above equate to approximately \$127 million to \$143 million per year, depending on whether California's costs are included in the mix or not.

As RTOs mature and more such organizations become operational, parties can hope that experience will drive startup and operating costs down. The data from ERCOT and Ontario do not necessary demonstrate that RTOs have yet benefited from this learning curve. Conversely, however, the startup of Ontario and ERCOT do suggest that costs are being contained rather than significantly increasing, as the California ISO's experience, taken alone, would have suggested. These data are therefore seen as solid benchmark for average ISO/RTO costs. To the extent that RTO West could "beat the averages" and start up and/or operate for less cost, the overall RTO West net benefits would increase.

[41] Even the \$.58/MWh RTO, Ontario, is somewhat of an "outlier", with the next most costly RTO at \$.46, and represents a relatively small service area.

[42] From the Energy Impact Analysis TCA estimated approximately 280 TWh annual energy.

4.2 Operations of Secondary Exchanges and SC Functions

The RTO West benefit/cost study group directed TCA to examine the costs of secondary transmission exchanges. TCA chose to broaden the review to include both energy and transmission exchanges and ultimately found that there are no exchanges that specialize in transmission products alone, and few that offer the exchange of transmission rights, for example, at this time.

TCA was also asked to examine the costs of operating a Schedule Coordinator (SC) function, the role played by market participants (or third-party agents) to provide market participant interfacing roles with RTO West.[43]

The discussion of these topics in this report has been grouped here for two primary reasons:

- Minimal cost data are available for both of these functions because providers are primarily private and in many cases the functionality is only partially in support of the exchange or SC function.
- Some of the exchanges will also provide from minimal to substantial portions of the SC functionality.

TCA used several techniques to collect data reflecting the costs of these services, including:

- Conducting an original survey of members of the Association of Power Exchanges,
- Conducting an original survey of SCs and Qualified Scheduling Coordinators (QSEs) in the California and ERCOT markets,
- Using previous benchmarking works,[44] and
- Looking at published data on provider's web sites.

The survey questions are included in Attachments 4 and 5.

TCA received generous feedback from SC organizations and especially from members of the Association of Power Exchange throughout the world. However, data in this area are difficult to regard as intercomparable or complete. The most of these organizations are private, without standardized offerings. Comparing cost information is therefore less than satisfying.

[43] The Schedule Coordinator role is a significant one in markets where scheduling is primarily seen as communicating bilateral arrangements, such as in the RTO West, California and ERCOT. In such regions where a centralized pool is not operated in conjunction with the ISO or RTO, the Schedule Coordinator is the primary party who matches "buyers and sellers" or generators and loads. This role thus requires sophisticated scheduling systems, settlement systems and contractual arrangements to track, and aggregate and disaggregate, both the ISO/RTO schedules and the underlying portfolios of various sub organizations.

[44] Namely Cox.

4.2.1 Energy Exchange Information

Table 24 shows the data collected from various sources related to exchanges.[45] In many cases the data are incomplete; this was not surprising, given the extensive set of data that TCA was trying to collect.

To arrive at a proxy for average exchange fees, those exchanges that provided transaction fees were averaged, using a simple averaging, and doubling the transaction fee where it applied to both sides of the trade. From this simple analysis, a proxy price of $0.10/MWh was arrived at.

The transaction fees provide a proxy for the all-in costs of the exchange, including a profit margin. However, only a fraction of RTO West throughput would use the services of an exchange, namely that fraction that is not traded directly through bilateral arrangements and that is not provided to the RTO for balancing, redispatch, or ancillary services.

Although using an exchange causes parties to incur such an added cost, market participants would not use an exchange unless they believed that the benefits of doing so increased the value of their transaction by an amount equal to or greater than the

[45] Notes/Sources for the exchange data are as follows:

A. No complete set of either startup and operating costs data, or transaction fee data, was provided. TCA chose to use the transaction fee data, where provided, to average for a simple proxy. Parties are advised to estimate actual costs, and relevance of exchange data for themselves.

B. To develop the transaction fee average, TCA doubled the transaction fees if the exchange applied the fee to both buyers and sellers. The transaction fee averaging used a simple average, rather than weighted average.

C. Anonymity was offered to those responding to TCA's survey; exchange names have been suppressed to this end.

D. Exchange data for exchanges 1 through 6 are from TCA's international survey of exchanges, winter 2001 - 2002.

E. Exchange data for exchange 7 were gathered from the exchange's public web site.

F. Exchange data for exchanges 8 through 11 are from Cox, op. cite.

transaction costs.[46] As a matter of fact, these types of exchanges exist today, regardless of the existence of an ISO or RTO; the use of an exchange is not a directly incurred incremental cost of putting an RTO in place.

Exchange costs often include the costs of scheduling with the system operator/RTO, thereby offsetting the need for SC infrastructure.

[46] The Energy Impact Analysis, did, however, assume that markets are liquid. To the extent an exchange is needed to ensure that, this cost can be seen as incremental, relative to the energy impact benefits.

Table 24: Summary of Exchange Costs

Exchange	Type(s) of Market(s)	Primary or Secondary	Annual Volume (ranges)	Number of Control Areas	Start-up Capital Cost US$Million	Operating Cost US$Million	Transaction Fee (per MWh) US$	Transaction Fee Applied to:
1	Energy: day-ahead and intra-day	Primary physical and secondary financial	40,000 GWh to 70,000 GWh	1	10.85	6.83	0.069	buyers and sellers
2	Energy: spot (hourly and blocks)	Not available	<10,000 GWh	6	11.60	Not provided	0.036	buyer and seller
3	Energy: spot, forward	Primary. An exchange to match bilateral trades.	<10,000 GWh	6 (note 1)	3.9	2.5		
4	Energy: day-ahead	Primary	10,000 GWh to 40,000 GWh	1	Not provided	3.9		
5	Energy: real-time, reserves	Primary	40,000 GWh to 70,000 GWh	1	4	4.0	0.138	buyers and sellers
6	Energy: day-ahead, forward	Primary	<10,000 GWh	1	2.5	Not provided		
7	Energy: spot, forward		10,000 GWh to 40,000 GWh		Not available	Not available	0.002	contracts
8							0.030	buyers and sellers
9	Energy: spot, forward; clearing facility		> 100,000 GWh			1.00	0.028	buyers and sellers
10			> 100,000 GWh	1		62.00		
11			> 100,000 GWh			5.70		buyers
Average charge per MWh traded (note 2)							0.10	

Notes: (1) Six Transmission Areas
(2) Transactions applied to buys and sells are doubled for purposes of average

4.2.2 Schedule Coordinator Costs

TCA conducted a survey of SCs and QSEs. However, few respondents provided meaningful information other than suggesting directly or indirectly that it is very difficult to provide cost information because their operations are integrally connected to their other business functions. TCA therefore has no broad quantitative results to provide related to this topic.

There are, however, several pieces of information that may be useful to those contemplating the effort to establish this SC functionality.

First, exchanges, as described above, to greater or lesser extents provide scheduling services in addition to exchange platforms. Therefore, the exchange fees quoted above may also cover some SC functionality. Perhaps the most applicable case of this to the northwest markets is the services provided by the Automated Power Exchange (APX). Although conceived primarily as an exchange, APX has found its competitive advantage to be its ability to provide full-service SC services. APX provides these services in the California ISO market and in ERCOT and further was selected by ERCOT to be the "Default QSE," able to provide QSE services should any other QSE default, for example.

APX charges $0.0625/MWh to schedule power into the California ISO and $0.08/MWh for scheduling in ERCOT. These fees provide one indicator of the cost of providing SC services. Generally, small market participants may rely on APX for schedule coordination, because startup costs and the costs of 24/7 operations are viewed as prohibitive relative to the simple transaction fee. Mid- and large-sized participants, on the other hand, generally prefer to establish their own SC functionality, and they must therefore find that it is cost-effective, all things considered, to be their own SC, relative to the $0.0625/MWh and $0.08/MWh APX fees. This provides some understanding of order-of-magnitude costs.

Additionally, many of the functions of the SC overlap with existing infrastructure, so that not all of the effort to provide schedule coordination is incremental. In the responses received, the SC role was viewed as being a value-added service. For one relatively small participant (approximately 1000 GWh/yr throughput), the startup costs were seen as nominal, with slight modifications made only to existing systems, policies, and procedures. Further, for this participant, personnel costs were minimal, because marketers, traders, and schedulers simply picked up the SC functions.

In summary, the cost to set up and operate as a Scheduling Coordinate is often seen as significant. However, upon inspection one finds that many of the SC functions are business functions that many participants are already providing. SC costs can be seen as bound by the costs charged by a full third-party provider such as the APX, because should a party not wish to make the initial and ongoing investment, they could choose to contract for the services at $0.06 to $0.08/MWh. Additionally, of survey respondents, at least a good fraction believed that their investment in the SC function produced net value for the organization.

4.3 Value of Loss of Load

The study group has had an interest in quantifying the financial impacts of reducing the number and/or duration of outages (loss of load, or LoL), should an RTO structure be shown to improve reliability. Although TCA was not tasked with quantifying such LoL reductions, TCA did endeavor to examine what has been published on their value.

Several appropriate sources of data were identified. First, voluntary load-reduction programs are in place throughout the country, generally paying hundreds of dollars per megawatt-hour of curtailed load.[47] For two reasons, however, such values may significantly underestimate the value of load interruptions. First, load curtailment programs have varying degrees of notification, but in all cases participants can anticipate being interrupted at some time. Awareness of the possibility of interruption varies widely, from optional daily participation, to calls by the ISOs or Control Areas, to a simple awareness of the likelihood of a curtailment resulting from the participant's agreement to participate in the programs. Second, with all the programs listed below, only a fraction of all load participates in the program. Assuming that loads whose opportunity cost is less than the payment for curtailment or possible curtailment participate, that means that for these other consumers, the cost of loss of load exceeds the value of the program compensation.

For involuntary load curtailments, several sources of data suggest that the impacts can be tens of thousands of dollars per megawatt-hour.

- A recent study performed on behalf of the California Manufacturers' Association found the impact of rolling blackouts in California to be approximately \$30k/MWh.[48]
- Further studies have found values of LoL to range from \$10k/MWh to \$50k/MWh.[49]

[47] TCA collected some actual data, for example the CA Demand Relief program pays \$500/MWh plus a capacity payment for participating of \$20k/MW-month, the CA Discretionary load reduction program pays \$500/MWh to \$700/MWh, the NY Emergency Demand program pays at most \$500/MWh, as does the PJM Emergency Load Response program. However, the effort did not look across all programs such as utility programs, nor did it attempt to capture all the relevant facts of each program. Order-of-magnitude impacts seem relevant here.

[48] "Impact of Continuing Electricity Crisis on the California Economy," AUS Consultants, May 2, 2001. Report suggests \$6.8 billion direct costs and \$14.9 billion of indirect costs. Given 20 hours of rolling blackouts and 3647 MW of total CA load, this represents roughly \$30k/MWh.

[49] From Power System Economics, Steven Stoft, draft publication (publishing anticipated for May 2002), Part 2, "Reliability, Price Spikes and Investment." This section reports on a value of loss of load determined in Australia of \$16k/MWh, and a LoL of \$10k/MWh used for the purpose of purchasing

Regardless of the specific value employed, it is clear that a significant change in LoL duration or frequency, determined theoretically to accompany the implementation of the RTO, could easily amount to a significant potential benefit for the northwest.

installed capacity. The study further reports that trading agreements in England value loads at greater than $50k/MWh, although Stoft is unclear as to whether this is $US, or $CA

5 Additional Impacts: Qualitative Assessment

TCA investigated a variety of additional benefits and costs that were not quantified. These additional items are discussed in this section. Many of these benefits are viewed as material to impacts of an RTO, and the cited basis for RTOs often reflects these types of attributes. For this study, however, no quantification was attempted given the level of effort and likely controversial nature of the results. The study also did not attempt to evaluate the extent to which these benefits or costs have played out in other markets.

The additional areas of impact have been grouped into four topic areas:

- RTO focus, coordination and information exchange.
- RTO consolidation of functionality.
- Organizational relationships established by the RTO process.
- RTO independence.

Each of these areas is discussed below in more detail.

TCA also surveyed marketers in the northwest, addressing perceived benefits of the RTO. The results from that survey complement the direct discussions of the areas of benefits and follows at the end of this Section 5.

5.1 Focus, Coordination and Information Exchange

One of the major areas of impacts of an RTO comes from the improved ability for the broader system operator (RTO) to focus on operations in the region and to coordinate activities to allow for easy information exchange. Benefits in this area seem to far outweigh costs. This section presents the details of the benefits, followed by a discussion of neutralizing impacts and costs.

5.1.1 Potential benefits

There are many areas of potential benefits related to focus, coordination, and information exchange. These are discussed as follows:

5.1.1.1 Planned outage management

The Energy Impact Analysis examined the impacts of improved generation outage planning, by looking at the value of planning generator outages based on the more global northwest market, rather than within each control area. However, the RTO's "big picture" perspective will also allow it to make more accurate assessments of the effect of proposed maintenance schedules on reliability.

RTOs have the authority to approve and disapprove all requests for scheduled outages of transmission facilities to ensure that the outages can be accommodated within established reliability standards. Control over transmission maintenance is a necessary RTO function because outages of transmission facilities affect the overall transfer capability of the grid. If a facility is removed from service for any reason, the power flows on all regional facilities are affected. These shifting power flows may cause other facilities to become overloaded and thereby adversely affect system reliability.[50]

For example, when the owners of a constrained interface between MAPP and MAIN tried to remove the line from service for maintenance, they found that 500 MW of flow remained on the line even after all scheduled transactions were terminated. There were so many transactions in the region at the time that transmission operators could not determine the source of this 500 MW loop flow and were unable to ask other parties to cut their schedules to permit the necessary maintenance.[51]

The RTO's "big picture" perspective will allow it to make more accurate assessments of the reliability effect of proposed maintenance schedules, taking into account system-wide effects and seasonal demand variations.

5.1.1.2 Reduced failure propagation and improved outage restoration

The geographically fragmented approach by which the transmission system is operated today can allow system operators in one area to act without realizing the security implications for other neighboring areas, frequently with significant consequences. A case in point is the massive outage in the west that occurred during the summer of 1996, when a Bonneville Power Administration transmission line sagged too close to a tree, causing a flashover that led to cascading transmission line outages and subsequent generation outages. In total, nearly 7.5 million customers lost power, for periods ranging from several minutes to as long as nine hours. Transmission systems in 14 states, Canada, and Mexico were affected. Key factors that allowed a single transmission line outage to lead to significant regional losses were inadequate contingency plans, operating studies, and instructions to dispatchers.[52] The existence of an RTO would have reduced, if not prevented, this event.

The RTO, through tightened communications and coordination, may reduce conditions that cause failures to propagate throughout an entire region, relative to the geographically fragmented approach by which the transmission system is operated today.

Furthermore, a single integrated operator would likely be able to restore system operation following an outage more quickly and in a more-orderly way than can separate control area operators.

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[50] FERC Order 2000, p. 319.

[51] Ibid, p. 40.

[52] *Western Systems Coordinating Council Disturbance Report for the Power System Outage that Occurred on the Western Interconnection August 10, 1996;* October 18, 1996, posted online at www.wscc.com/news_regrading_power_outages.htm

5.1.1.3 Voltage/frequency management

Frequency oscillations outside of an acceptable range have the potential to impose damaging stresses on generating machinery and large motors and can upset the stability of the entire grid. It is not uncommon for neighboring control areas in the Eastern U.S. to experience frequency oscillations because of the interaction between generating units in their respective areas. An example of this type of interdependence among control areas within a region is presented in the *1998 MAAC Reliability Assessment* (April 28, 1999) www.maac-rc.org.

In the northwest the maintenance of voltage stability is of greater practical importance than frequency. The RTO West would likely provide increased ability to manage frequency and voltage given its broader information and broader, coordinated control of transmission and generation resources and loads

5.1.1.4 Loop/parallel path flow

Loop flows can pose a significant security challenge for the neighboring power grids because all the unscheduled electrical paths that lie outside of relevant control area boundaries are not under the control and oversight of a single operator whose systems must accommodate these unplanned power flows. According to an EIA report:

> This cross-over can create compensation disputes among the affected transmission owners. It also impacts system reliability if a parallel path flow overloads a transmission line and decisions must be made to reduce (curtail) output from a particular generator or in a particular area. An RTO with access to region-wide information on transmission network conditions, with region-wide power scheduling authority, and with more efficient pricing of congestion can better manage parallel path flows and reduce the incidence of power curtailment. [53]

Thus, the ability to better manage loop flow directly affects the reliability of the system; it should also allow for the removal of overly conservative Available Transmission Capacity (ATC) requirements and should ease intercontrol area checkouts and settlements, as described below.

5.1.1.5 Scheduling, System Monitoring, Checkouts and Settlements

Several categories of information exchange will be automated or will no longer be required with an RTO:

- Information on schedules, system state, and real-time flows on interacting transmission elements (nomograms);

[53] Energy Information Agency, *The Changing Structure of the Electric Power Industry 2000: An Update*, Chapter 7, October 2000, posted online at www.eia.doe.gov.

- Real-time check-out and coordination of schedules and reservations on inter-control area ties;
- Inadvertent interchange and accounting, data collection and data sharing, and settlement.

Much of the cost and complexity of an RTO arises from integrating the control areas and automating the management of information. The benefit of these activities is ongoing avoided effort in these areas. This results in the elimination of these costly activities within each control area, and more importantly efficiency improvements, possibly higher ATC levels, and better ability to manage the reliability of the system.

5.1.1.6 *Impacts of a Single Control Area on Transmission Capacity and Regulating Reserves*

Given the improved focus and coordination with an RTO, available transmission capacity (ATC) will likely increase[54] due to a variety of mechanisms:

- A reduced need to set aside transmission capacity to compensate for the inability to manage transmission and generation resources in neighboring control areas. Without the ability to have full knowledge of the actions of adjacent system operations or to have control over adjacent systems, ATC may have built-in levels of conservatism beyond the scheduling limits evaluated in the Energy Impact Analysis.
- Better scheduling of transmission line maintenance, as described in Section 5.1.1.1, should result in higher overall availability of transmission capacity.
- Standard approaches to defining path ratings and transfer capabilities. As stated in FERC Order No. 2000, an RTO of sufficient regional scope can make more accurate determinations of ATC across a larger portion of the grid using consistent assumptions and criteria.[55] Because the RTO would be at least partially responsible for developing standards and ATC criteria, such development should produce more consistent guidelines, which should ultimately allow higher levels of ATC.

5.1.1.7 *Automatic Generation Control (AGC)*

To the extent that benefits have not already been captured through the regional reserve sharing policies, AGC requirements will decrease mainly because of higher load diversity and larger geographic regional requirement determination.[56] Further, as with the impacts

[54] Such increases in ATC were not incorporated into the Energy Impact Analysis. Higher levels of ATC could be modeled, but for the difficulty in estimating the resulting increases of these factors with any degree of certainty.

[55] FERC Order No. 2000, p. 255.

[56] The October 2000 study quantified potential benefits of lower regulating reserve requirements and found that 364 MW fewer of regulating reserves would be required with the RTO due to the load diversity (295

of operating reserves in the Energy Impact Analysis, having available more efficient resources for regulating reserves will reduce the costs of reserves. Additionally, although the Energy Impact Analysis evaluated savings in operating reserves arising from more efficient provision of those reserves, as with AGC, single largest contingency requirements may further decrease with an RTO. To the extent that the single largest contingency causes higher levels of reserves to be required, the RTO may allow for eliminating the reserves for some of these contingencies.

Similarly, to the extent the northwest control areas have required additional reserves for use of non-firm transmission between existing control areas, this need should decrease or disappear within the RTO region as a result of the RTO overseeing all of the delivery of resources (energy or reserves) within the northwest. The need for reserves to cover interruptible imports is based on the fact that imports may be interrupted at the discretion of external system operators, whose actions cannot be controlled or anticipated. This risk is practically eliminated between all contiguous member control areas within RTO West, since a single control area operator would control them all. This significantly reduces reserve requirements. Additional reserves for on-demand obligations may not change, however, because contractual obligations may remain under a single control area.

5.1.1.8 Real-time Balancing Efficiency

With the consolidation of control areas, RTO West will have several options for performing real-time balancing and regulation. Depending on their choice of implementation and on the historical diversity of area control error (ACE) in the member control areas, RTO West may save significant resources through centralization of the regulation and balancing function as a single control area and the existence of a single, aggregated ACE. This will eliminate the need for management of inadvertent interchange between member control areas, which at present perform regulation and balancing individually with their own ACE. Schedules on what are currently inter-control area ties will be managed under a single control area, just the same as schedules on any internal transmission paths. This will permit an aggregation and simplification of the balancing and settlement function.

5.1.1.9 Long-term planning and expansion benefits

In Order No. 2000, the FERC states that the RTO must have ultimate responsibility for both transmission planning and expansion within its region, because "a single entity must coordinate these actions to ensure a least cost outcome that maintains or improves existing reliability levels. In the absence of a single entity performing these functions, there is a danger that separate transmission investments will work at cross purposes and possibly even hurt reliability."[57]

MW) and relaxed standards (69 MW). When valued at Bonneville Power Administration's cost of service this quantity of regulating reserves was valued at $28 million. TCA in this study has made no effort to quantify these savings or to validate the October 2000 study conclusions.

[57] Ibid, p. 486.

Moving to an RTO with regional authority for transmission planning would avoid current problems arising from transmission planning based on local or sub-regional needs. In the current environment, transmission expansion has not kept pace with the changing needs of the market. Although levels of commerce in electricity are increasing, very little is being done to increase the load serving and transfer capability of the bulk transmission system.[58] According to EPRI, failure to satisfy grid expansion needs is resulting in increasing frequency and duration of power disturbances and outages costing $50 billion per year.[59] These failures stem from three root causes: the existing institutions have incomplete information on actual operating conditions, their unilateral responses to conditions are often ineffective, and their approach to planning is myopic. The last point is particularly important, because current institutions consider only the *local* benefits of transmission investments and upgrades, although the actual benefits obviously extend well beyond the control area where the upgrade occurs.[60] The benefit of such investment is therefore undervalued, and improvements that are critical to the regional electricity needs are not made. The creation of a large, regional RTO will allow it to "address larger issues that affect an entire region, including planning and investing in new transmission facilities…."[61]

Generation additions would also likely be more optimal, given that an RTO will create more efficient locational price signals, and that a broader market will allow more efficient use of generating resources (more baseloaded units, and a reduced need for service area peaking units). As the RTO results in lower capacity requirements, benefits will be recognized in the long run through reduced need for additions to generating capacity.

5.1.2 Neutralizing impact of RTO Focus, Coordination, and Information Exchange

The above discussions link benefits in focus, coordination, and informational areas to the RTO. However, ongoing industry coordination may create benefits even absent RTO formation. To the extent this occurs, or would occur, benefits cannot be attributed directly to the RTO formation.

5.1.3 Potential costs of RTO Focus, Coordination and Information Exchange

Some parties believe that by forming a large, centralized RTO, the unique experience of the operators of individual transmission systems may be lost or diluted.

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[58] Reliability Assessment 2000-2009, NERC, October 2000, p. 26.
[59] FERC Order No. 2000, p. 44.
[60] FERC 32,541 at 33, 702-03.
[61] FERC Order 2000, p. 63.

5.2 RTO Consolidation of Functionality

In addition to the benefits of coordination and broader perspective, the consolidation will also offer some direct efficiencies and cost savings.

5.2.1 Potential benefits

5.2.1.1 Cost Effectiveness

A single RTO should be more efficient as the breadth increases, thereby reducing costs relative to the sum of the costs of the individual control centers.

5.2.1.2 Having a Single OASIS Site Should Reduce Costs and Improve Liquidity

The benefits of having a single OASIS administrator are several. A single OASIS administrator over an area of sufficient regional scope would better allocate scarcity as regional transmission demand is assessed; promote simplicity and "one-stop shopping" by reserving and scheduling transmission use over a larger area; and lower costs by reducing the number of OASIS sites....[62] In addition, a single OASIS site for each region instead of multiple sites would enable transactions to be carried out more efficiently.[63] Finally, standardization should help liquidity within RTO West and should facilitate seamless trades across the RTOs.

5.2.1.3 A Single Region-Wide Tariff Will Reduce Costs and Encourage Market Competitiveness

Maintaining a single tariff should produce benefits in the overall effort required to maintain tariff language, relative to what is required with each transmission owner maintaining a tariff, and should reduce costs of operation for market participants using the tariffs. This should also provide the added societal benefit of leveling the playing field, thereby allowing broader market participation.

5.2.1.4 Standardized Business Practices

Terminology and operating practices vary with OASIS sites. Because current market participants have to deal with multiple OASIS sites, transactions are limited because of the complexity of dealing with different systems and understanding different procedures. In addition to standardized tariffs, other business practices will be standardized with the RTO, thereby reducing transaction costs of market participants.

[62] FERC Order 2000, p. 255.
[63] Ibid, p. 432.

5.2.2 Neutralizing impact

Similar to impacts related to focus and breadth, ongoing industry standardization may create benefits even absent RTO formation.

5.2.3 Potential costs

An RTO may be more complex and may therefore cost more for market participants to schedule and settle with than would each individual control area.

5.3 The RTO Formation Establishes New Relationships

5.3.1 Potential Benefits

5.3.1.1 The Legal Relationships Created by the RTO May Provide an Enhanced Business Structure

By working through legal liability issues, the formation of the RTO may reduce the total costs of managing liability between parties. This could manifest itself as the ability to more quickly establish business relationships, for example.

5.3.1.2 Credit Management is Formalized by the RTO

The RTO will put in place structures that will facilitate, to some extent, credit management and it may provide a forum for resolution of ongoing regional/local regulatory issues.

5.3.2 Potential Costs

5.3.2.1 Resources are Required to Form New Relationships

Although direct RTO costs are likely rolled into quantified RTO cost data, developing relationship structure requires stakeholder resources pre-RTO. For example, the considerable time involved in stakeholder processes such as this benefit/cost study is rarely valued as part of the cost to implement an RTO.

5.3.2.2 Entity Tax Implications

An RTO may result in new tax treatment. However, the details of such an assessment were outside the scope of this benefit/cost study.

5.4 The Independent Nature of the RTO

5.4.1 Potential benefits

The RTO's independent transmission maintenance scheduling is viewed by some to be advantageous. A transmission owner that also owns generation may have an incentive to schedule transmission maintenance at times that would increase the energy price, thus increasing generator revenues. A transmission company, not affiliated with any generators, would not have these same incentives. Similarly, RTOs may eliminate—through structural separation—the economic incentive to act in ways adverse to other control areas in the region. Finally, an independent RTO would remove any mechanism for influencing ATC values based on energy portfolios.

5.4.2 Potential costs

Separating transmission operations from generation operations requires formalizing management of the interrelationship of generation impact on transmission and transmission impacts on generation (e.g., formal procedures and/or markets would be needed for VAR control).

5.5 Survey of Marketers in the Northwest

5.5.1 Intent

To provide a validation of theoretical potential benefits, the study scope included a direct survey of market participants. TCA conducted telephone interviews on behalf of RTO West with seven market participants[64] to get their views on the pros and cons of RTO West as it is currently configured. The survey questions (listed below) were developed by the study group. The survey interactions themselves were often more wide-ranging than is suggested by the questions.

[64] Ten market participants were contacted, but only seven interviews were completed prior to completion of this report. They are: 1) Pennsylvania Power & Light (PP&L) Montana; 2) TransAlta Corporation; 3) UBS Warburg (formerly Enron); 4) Calpine Corporation; 5) Alberta Power Pool; 6) Mirant Americas; 7) Powerex Corporation.

Standard Survey Questions

(1) What do you see as being the benefits of having an RTO (and specifically, the footprint and configuration of RTO West)?
- One-stop-shop for services
- Single tariff
- Single set of Business Practices
- Competitive Ancillary Services market
- Other

(2) What do you see as being the detriments of having an RTO (again, relating to RTO West)?
- Reliance on one entity
- Uncertainty, given the expectation that the RTO, once up and running, will determine the specific details that will affect marketing efforts.
- Issues re: the configuration of RTO West
- Seams issues
- Other

(3) In answering the above questions, did the configuration/proposed operation of RTO West affect your answers?

Most participants took the interview seriously and appreciated the fact that RTO West would seek feedback from market participants and the opportunity to provide their own opinion. The seven market participants reached were mostly project developers or power marketers, with the exception of the Alberta Power Pool. Thus, they had a common standpoint and similar expectations of the market, as is reflected in their responses.

5.5.2 Outcome

Overall, participants expressed strong support for the formation of RTO West. The main benefits cited were (1) the elimination of rate pancaking, (2) the standardization and centralization of the tariff and of business practices, and (3) the prospect of increased market liquidity and transparency from a larger, centralized energy market. Other benefits, expressed by fewer respondents, included standardization of generation interconnection agreements, the reduction of transaction costs through one-stop shopping, and the likelihood of a more stable investment environment for capacity expansion.

The almost unanimous concern expressed by the respondents was that the current proposal runs the risk of undermining the objectives of RTO West. Specifically, most respondents felt that the grandfathering of transmission rights inhibits the creation of a liquid transmission rights market because incumbents may not have financial incentives to release these rights in a secondary market. A second concern expressed by the six power marketers was that the rules preclude a true level playing field in the market between new entrants and incumbents. In addition to the grandfathering of transmission rights, the transmission access fee also contributes to this sentiment. Although they acknowledged that the incumbents paid an access fee based on their company rate sheet, they pointed out that incumbents would receive congestion rights with transmission access, but new entrants would not. Under FERC Order No. 888, all transmission users were accorded congestion rights on purchasing transmission, but under RTO West only incumbents continue to receive this benefit. Further, the access fee would render a significant number of previously economical transactions uneconomical in the new regime.

5.5.2.1 Select Survey Participant Comments

Below are paraphrases of some individual comments received during the interviews. These were chosen either because they offer more detail on the above summary points or because they reflect a less heard, but valid, consideration.

- A single tariff is particularly advantageous to merchant generation, because it provides a stable investment environment in the form of a large regional, liquid, accessible energy market. This will help in securing project financing.
- Marginal cost of trading will likely decrease under RTO West.
- Alberta marketers will benefit tremendously for export and import purposes from standardization and tariff simplification under RTO West.
- Market participants may have to give up existing competitive advantages and create new ones, because markets under RTO West may demand different skill sets. For example, scheduling in WSCC was a core competence in the past, but may not be as important if RTO West "accepts all schedules." Rather, other skills such as settlement complexities may gain importance.
- Alberta power marketers would favor integration of BC Hydro into RTO West, because that would reduce the seams they would to cross in order to transact with the U.S. However, membership of Alberta in RTO West would face significant legal hurdles, as well as significant learning curves in terms of the incorporation of congestion rights and pricing in Alberta.
- Grandfathered transmission rights slow down market development, and should at least be phased out with time. The current proposal will likely create barriers to entry to new participants, because incumbents will have little incentive to sell transmission rights that are most in demand, namely those that are likely to face congestion.
- All generators, including existing ones, should be on generation interconnection agreements in order to create a level playing field.
- The absence of a day-ahead, centralized power pool will hurt market efficiency and flexibility to market participants.
- The efforts required to resolve seams issues with the other two RTOs may be better spent in integrating all three into a single Western RTO.

6 Market Concentration Analysis

6.1 Introduction and Objectives

A market concentration analysis of the RTO West region was performed as part of the benefit/cost study performed by TCA for the RTO West Filing Utilities. The objective of this analysis is to provide an initial estimate of the market concentration in the region both before and after implementation of the RTO. This analysis identifies geographic regions and load centers that are highly concentrated and that could therefore experience high prices as a result of market power abuse. This type of market concentration study reflects the concern of the Federal Energy Regulatory Commission (FERC) over market power in electricity markets, as is discussed in FERC Order No. 2000, *Regional Transmission Organizations.* As referenced in this Order, the Federal Power Act gives FERC the primary responsibility to ensure that regional wholesale electricity markets operate without market power. In Order No. 2000 the Commission found that RTOs would be needed to resolve impediments to fully competitive electricity markets. As independent entities with no financial interest in the wholesale market, RTOs will also reduce the potential for market power abuse by mitigating potential vertical market power.

To maintain ongoing market power analyses, the Commission proposes in Order No. 2000 that RTOs perform a market monitoring function, which would include monitoring transmission service, ancillary services, and bulk power markets, and providing reports on market power abuses and market design flaws. Appropriate market monitoring, FERC states, provides an objective basis to observe markets and, if appropriate, to produce reports and market analyses.

The market concentration analysis reported in this study was performed according to the FERC Competitive Analysis Screen (Appendix A of the FERC Electric Merger Policy Statement, Order No. 592) to provide a baseline for possible future strategic market power analyses in the RTO West region and for future filings with FERC by the RTO West Filing Utilities.

6.2 Definition of Market Power

Market power is generally defined as the ability of a particular seller, or group of sellers, to significantly influence the market price of a product to its advantage over a sustained period. Regulators typically look for a combination of incentive and ability, because ability alone does not necessarily mean that prices will be raised. However, experience with electricity markets in the United States and other countries makes it clear that the threat of market power is real and that the exercise of market power can result in prices above the competitive level.

There are numerous negative implications when market power is exercised, among which the following are perhaps the most significant:

- Inefficient operation of the electric power system as out-of-merit-order (expensive) generators are dispatched.
- Distorted incentives for technological investments as a result of distorted market signals.
- Compromised long-term system reliability resulting from distorted market signals and consequent insufficient investment and system expansion.
- Financial harm to consumers through higher prices.

Market power is often equated to market concentration, as it is in Appendix A of the FERC Electric Merger Policy Statement, Order No. 592. However, there is no direct theoretical link between the Herfindahl-Hirschman Index (HHI), or other measures of market concentration, and measures of market power. Therefore, although the HHI can be used as a simple indicator of the *potential* exercise of market power, it does not measure market power directly.

6.3 Market Concentration Analysis Methodology

6.3.1 Overview

The analysis presented in this study determines market concentration. A "market" in this context refers to the collection of all entities that can provide power to a geographic region under a specific set of conditions. In this analysis, each hour of the year is considered to fall into one of 12 "product markets" in each utility service territory: for each of the four seasons (winter, spring, summer and autumn), a given hour is categorized according to load as Off-Peak, On-Peak, and or Super-Peak. This analysis is performed for both the long-term capacity and the short- and mid-term energy markets, as described below under Native Load Obligation.

While it is useful as an initial screen, the market concentration analysis is inherently a snapshot analysis that does not take market dynamics into account. It is a measure of how access to the market is apportioned given a certain set of market conditions. If conditions change, for example through a change in price or transmission system state, the market concentration can change as well.

The standard U.S. Department of Justice (DOJ) anti-trust measure of market concentration,[65] and the index calculated in this analysis, is the Herfindahl-Hirschman

[65] U.S. Department of Justice and the Federal Trade Commission, "Horizontal Merger Guidelines," April 2, 1992. http://www.usdoj.gov/atr/public/guidelines/horiz_book/hmg1.html

Index (HHI). The data needed to calculate the HHI for an electricity market are the following:

- Market price of electricity.
- Marginal cost and ownership of potentially participating generators.
- Obligation of market participants to serve native load.
- Transmission costs.
- Available transmission capacity.

Once all of these variables have been evaluated, the economically and physically deliverable capacity of each generator can be determined. The generators are then assigned to the market participant that controls their output, either the owner of the plant or the purchaser in a long-term contract. The aggregate market participant shares, expressed as percentages, are then used to calculate the HHI as detailed below.

6.3.2 Steps and Assumptions for Market Concentration Analysis

The study of market concentration begins with a simulation of market conditions and prices in two scenarios, with and without RTO West in place. The outputs of these baseline market simulations, prepared using the production cost model GE MAPS, provide the foundation for the market concentration analysis.

The market concentration analysis is based on the Competitive Analysis Screen defined in Appendix A of FERC Order No. 592. This test is intended for use in evaluating proposed mergers, to determine if a market is or will become significantly concentrated as the result of a merger, and it has also been used by FERC in evaluating proposed RTOs. If there is a significant change in concentration as a result of the RTO implementation, or of a merger or acquisition, then a further analysis of the ability of market participants to exercise market power and thereby raise prices in an anticompetitive fashion may be warranted.

The goal of the market concentration analysis in this study is not to identify the market concentration implications of a proposed merger but to predict whether the electricity market in RTO West will be workably competitive and the extent to which the implementation of the RTO will affect market concentration in the RTO West region. It serves as an indication of whether the electricity market in RTO West is sufficiently concentrated to warrant concern about the potential exercise of market power by any one participant. This part of the analysis does *not* examine anti-competitive pricing or the potential impact of strategic behavior (raising prices or withholding capacity) on the region's electricity markets and customers. Such an analysis could be conducted as an additional phase in this study.

The following steps are required for performing the market concentration analysis:

- Definition and identification of geographic markets.
- Definition and identification of energy product markets.

- Identification of potential suppliers of each product to each geographic region.
- Determination of native load obligation assumptions.
- Calculation of market shares and market concentration in the identified markets.

6.3.2.1 Definition of Geographic and Product Markets

Geographic Markets

The first step in defining a geographic market is to select a load center from which to begin the analysis. The second step is to identify suppliers capable of serving this load center. Suppliers are included if they are able to deliver the product (accounting for transmission constraints, costs and losses) to the customer at a cost no greater than 5% above the competitive price[66] to that customer. Taken together, the load center and the set of suppliers constitute the geographic market.

Our analysis thus begins with determining load center/destination markets based on the similarity of nodal prices with in each load center. Next, for each load center, all potential suppliers that could compete to serve that destination market are identified. Nodal prices for all load centers in RTO West (from GE MAPS) are analyzed using a clustering technique to identify buses that could be aggregated into a distinct electricity market or load center. Each cluster of buses is then designated as a destination market.

The clustering analysis includes all generator buses in the WSCC and load buses of 115 kV or above, for a total of 1,949 buses. The prices at these buses, taken from the GE MAPS output for the "With RTO" case, are then analyzed using the FASTCLUST procedure in SAS, and 15 clusters of buses are identified as appropriate destination markets for this analysis. In general, the majority of buses in each control area clustered together, as shown in Table 25. For example, 86% of the buses in Avista, and 93% of the buses in British Columbia Hydro Authority, fell into a single cluster associated with that company. The buses that did not fall in this main cluster were scattered in other clusters, in most cases in small groups of one to eight buses.

Two companies clearly divided into multiple clusters: Idaho Power Co. and PacifiCorp East. Transmission data were used to determine whether these companies should in fact be subdivided into smaller destination markets. On this basis it was decided to divide PacifiCorp East into two markets, PACE-UT for the Utah bus and PACE-WY for the Wyoming bus. Idaho Power Co. (IPC) is modeled as a single destination market, because its transmission capacity did not justify splitting this market into sub-markets.

[66] The competitive price is the price that would be expected in the market if all participants had perfect information and there was no market power. In this analysis, we assume the hourly competitive price to be the locational price calculated by GE MAPS. The competitive price used for the market concentration analysis, as discussed in this section, is then the simple average of these hourly locational prices across all buses in each load center.

Table 25: Percentage of Buses in Clusters

Control area	Percent of buses in single cluster	Where applicable, percent of buses in additional clusters	
Avista	86%		
British Columbia	93%		
Bonneville	95%		
Idaho Power	47%	29%	
Montana Power	88%		
Nevada Power	91%		
NorthWest PUB	99%		
PacificCorp East	36%	23%	22%
PacificCorp West	76%		
Portland	99%		
Puget Sound	100%		
Seattle	100%		
Sierra Pacific	61%		
Tacoma Power	100%		

The general conclusion from the clustering analysis is that the control area territories are an adequate proxy for destination markets. It is interesting to note is that this analysis indicates that a number of control areas, representing 1,278 buses in total, could have been merged into one destination market. These areas are the following:

- Avista
- Bonneville Power Administration
- NorthWest Publics
- Portland General Electric
- Puget Sound Power and Light
- Seattle City Light
- Tacoma Power Utility

However, these control areas were modeled separately in the analysis in order to maintain separate identification of ownership and market shares.

The twelve product markets

For each geographic market, there are 12 electricity product markets to represent the range of market conditions under which potential market power is screened. These product markets are Off-Peak, On-Peak, and Super-Peak defined according to load conditions during each of the seasons winter, spring, summer, and autumn.[67]

The product markets within each geographic market and season are defined as Super-Peak, Peak, and Off-Peak loads. These loads are defined on the basis of the maximum single-hour load in that geographic region during the given season. Starting with that

[67] Winter is defined as December, January, and February; the successive seasons are corresponding successive three-month intervals. In other studies, spring and autumn are often combined into one "shoulder" period. However, given the importance of hydro resources in this region we believe that distinguishing between spring and autumn is essential.

maximum single hourly load in each season, the hours of the season are categorized as follows:

Super-Peak =	Load is at least 95% of maximum hourly load
Peak =	Load is at least 80% but less than 95% of maximum
Off-Peak =	Load is less than 80% of maximum

6.3.2.2 Identification of Potential Suppliers

Once the hours that fall into each of the product markets in a region are identified, the price associated with that product market is computed as the simple average of the market prices for those hours as calculated by the GE MAPS production cost model. Consistent with the DOJ/FTC Horizontal Merger Guidelines and the FERC Competitive Screen Analysis, a price threshold for market participation (105% of the average price) is used to screen out suppliers whose cost of supplying energy to the destination market, including costs for production, transmission, and losses, is too high to warrant their participation in the market.

A generating unit within the geographic market is considered able to participate in a given product market if its marginal cost is less than or equal to the price threshold. A generator outside the destination market is considered able to participate in a given product market if its marginal cost of electricity, adjusted for losses, plus the minimum transmission cost to the destination market, is less than or equal to the price threshold. Any generating company that owns a generating unit that meets either of these standards is considered to be economically capable of participating in the given product market.

Assumptions with respect to the availability and costs of hydroelectric generation are critical to this analysis. Unlike thermal generating units, whose available capacity typically varies only slightly between seasons, the capacity of hydroelectric units varies considerably between and even within seasons, and this can substantially influence the results of the market concentration analysis.

Although hourly schedules of hydroelectric units were available, hydroelectric availability data were aggregated in order to be consistent with the snapshot analysis for the 12 product markets defined for the market concentration analysis. The capacity associated with each product market was calculated as follows.

- First, we assumed that in all Super-Peak hours, the hydroelectric unit is available at its *maximum annual capacity*. Super-Peak periods are very short, ranging from 34 hours in winter to 71 hours in the autumn, so it is reasonable to assume that the resource could be available at its maximum capacity during the Super-Peak hours in all four seasons. This is true even though the historical maximum schedule in a given season may be less than the nameplate capacity.

- Second, for the Peak period in each season, we assumed that the level of availability will be equal to the *maximum scheduled capacity in that season*. In RTO West, Peak hours comprise more than half all operating intervals. However, the need to react to high prices may not necessarily exist during all those hours. Therefore, for the purpose of the market concentration analysis, it is reasonable to assume that the capacity available to react to high prices will be at the level corresponding to the highest output scheduled in a season.
- Finally, during Off-Peak hours, we assumed that the capacity available is equal to the *average scheduled capacity* in each season. This level is higher than the average use of capacity scheduled for Off-Peak hours, indicating that if it were necessary to react to higher than normal prices, hydroelectric resources could be used at the seasonal average scheduled levels. This assumption recognizes the reluctance of operators to increase the use of hydroelectric resources in Off-Peak hours to levels significantly exceeding the scheduled level.

Transmission Constraints

Transmission into the geographic markets is limited by the physical transfer capability of the transmission system. For the WSCC, transmission constraint data were taken from the WSCC path limits, as provided to TCA by the RTO West participants. For the purposes of this analysis, TCA assumed that transfer capability at each transmission constraint is apportioned pro rata to the generators on the upstream side of the constraint that have been found to meet the 105% economic test. A generator that requires transmission service across more than one constrained interface to reach the destination market will see its deliverable capacity reduced at each successive constraint. Regardless of the availability of low-cost power in the surrounding areas, the total capacity that can be imported from all generators outside of the destination market region cannot exceed the import capability of the transmission paths into that market. Generating capacity that meets the price threshold within the geographic market and that is not restricted by transmission constraints is considered to be 100% available to the local destination market.

The total power available to a product market in any destination market is a function of market price, the price at which generators can deliver power to the market, transmission capacity into the geographic market, and the native load obligations (if any) of the potentially participating entities.

6.3.2.3 *Native Load Obligation in the Short-, Medium -, and Long-Term*

Three levels of native load obligation are assumed for this analysis: (1) an obligation to serve 100% of the current native load, (2) an obligation to serve 80% of the current native load, and (3) no native load obligation.

The assumption of 100% native load obligation means that market participants are required to withhold a portion of their least-cost capacity from the wholesale market to satisfy their native load obligations and other long-term wholesale contracts. This is interpreted as representing the short-term market, when participants remain obligated to serve both long-term contracts and native load.

The 80% native load assumption represents the possibility that there will be some opportunity for native load customers to switch suppliers and buy energy on the wholesale market, while the remaining native load is served directly by the traditional supplier. This scenario is modeled by assuming that companies retain 80% of their current native load obligation, while the remaining 20% is able to buy energy from the competitive wholesale market. The significance of this test to the market concentration analysis presented here is that it allows examination of market concentration in the near term, but after some retail access has occurred.

In the third case, it is assumed that there is no native load obligation in any of the markets included in the analysis, so that all market participants are allowed to sell all of their power on the wholesale market. This can be interpreted as representing the long-term capacity market.

Transmission Availability and Native Load Obligations

The amount of transfer capability made available to the wholesale market decreases as the native load responsibility increases. To understand this relationship, examine the case of no native load obligation first. In this case, all of the load is participating in the wholesale market and all generators are supplying the wholesale market. In this situation, the starting point for the analysis assumes that no generators are operating and thus no power is flowing. This implies that the total transfer capability of the transmission system is available to transmit power for the wholesale market.

In contrast, the 100% of native load case assumes that companies must serve that load before they sell any power to the wholesale market. In this case, the starting point for the analysis assumes two things that are different from the previous case.

1. Available supply. The lowest-cost generators of each company are used to supply their native load and so are not available to the wholesale market.

2. Available transmission. The fact that native load is being served first means that power is flowing in the initial state of the system for the 100% of native load case, which means that not all of the transfer capability of the transmission system is available to the wholesale market. Some of the transfer capability is being used to serve native load, and only the unused portion is available for transmitting power

for the wholesale market. This remaining transfer capability is what is assumed to be available for the 100% of native load case. TCA modeled two levels of transfer capability available after native load is served: 40% available and 85% available. These values were based on a survey of available transfer capability values posted on WSCC OASIS sites and other regional transmission trading sites. Because of the inconsistency of these posted numbers, two levels of available transfer capability were modeled rather than one.

6.3.2.4 Calculation of Market Concentration

Market concentration is calculated in three steps. First, the database of the power system, including generators, production cost data, transmission lines and constraints, and transmission rates, is used as described above with a computer model to determine which generators can economically and physically supply each destination market. Each destination market is analyzed separately, and all suppliers that can supply each market are assumed to participate in that market (that is, in order to ensure that all potential suppliers are included in the calculation, the local demand is essentially modeled as infinite, allowing all suppliers the chance to participate). The second step is to determine the market share of each supplier. Finally, the market concentration index is calculated.

Market concentration is calculated according to the DOJ/FTC Horizontal Merger Guidelines, which use the Herfindahl-Hirschman Index (HHI). The HHI is the sum of the squared market shares (percentages) of each of the market participants:

$$HHI = \sum_{i=1}^{N}\left(100 * \frac{P_i}{\sum P_i}\right)^2$$

where

N = Number of market participants,
P_i = Total capacity of participant i that meets the price threshold and is deliverable to the destination market,.

As a screening test, the DOJ interprets HHI values as follows:

HHI range	Interpretation
HHI < 1000	Unconcentrated Market
1000 HHI < 1800	Moderately Concentrated Market
HHI 1800	Highly Concentrated Market

6.4 Market Concentration Analysis Results[68]

Charts for the market concentration and market share results are presented and discussed below. The complete set of tables and charts is provided in the accompanying electronic data. Recall that market concentration as indicated by HHI is only an indicator of potential market power, not a measure of market power itself. If a supplier were to attempt to exercise market power in the RTO West region, with the intent of raising the price, the result would likely be that more generators would become economical and would therefore be able to supply energy to the affected market. This increase in market supply would counteract the attempted exercise of market power.

Figure 3 and Figure 4 show HHI results for each destination market in the RTO West region, With and Without RTO. Each HHI result presented is the average value for the indicated market across the 12 product markets analyzed. The values for all markets except IPC and Sierra Pacific Power Company (SPP) are well above the range considered to be highly concentrated by DOJ and FERC.

Figure 3 compares the HHI values With and Without the RTO, assuming that companies retain 100% of their native load obligation. Figure 4 shows the average HHI values for the scenario in which companies have no native load obligation, so that the availability of generation for participation in the wholesale market is determined solely on economic grounds (the results for assuming 80% native load obligation are provided in the electronic data.)

Comparison of the two bars for each company within a single chart (see also the non-averaged charts presented in the electronic data) shows that the HHI values within any given destination market are not significantly affected by the implementation of the RTO. The figure shows that the implementation of an RTO does not necessarily result in a decrease in market concentration; it may even result in an increase in some regions. Although seemingly counterintuitive, these results reflect the fact that sufficient low-priced power is available throughout most of the RTO West region to serve each destination market.

[68] The Market Concentration results are based on the GE MAPS nodal prices calculated for the March 5, 2002 draft of the report. The changes to the GE MAPS nodal prices between the March 5, 2002 draft and this March 11, 2002 draft are expected to have minimal impacts on these results.

This result is better understood by reviewing the market concentration results in conjunction with the seasonal prices for each destination market. In general, one would expect to observe that as electricity prices decrease, fewer regional generators would be able meet the economic test (that is, to deliver energy at less than or equal to 105% of the local price). In this situation, even though the costs for transmission and losses after the RTO is implemented would be less, they could still be high enough to prevent distant generators from being competitive. This leads to the result that as prices decrease, fewer generators are able to meet the price threshold, which has the effect of raising market concentration.

A second way to interpret Figure 3 and Figure 4 is to compare the HHI values for a single company between the two figures. This comparison demonstrates that market concentration in the *wholesale* market tends to be higher when companies retain their native load obligation than when there is no longer an obligation to serve. The comparison across the figures shows that when companies serve their historic native load with the least expensive generation (Figure 3), leaving only the more expensive generation to serve the wholesale market, market concentration is higher than when all generation is made available to the wholesale market (Figure 4). The assumption of a native load obligation leads to higher HHI values in most markets and for most of the 12 product markets, because fewer suppliers have excess capacity available to serve the wholesale market. However, because the native load is being served by the least-cost generators, the native load costs would not be affected by strategic bidding in the residual wholesale market.

HHI values provide information on overall market concentration. Further insight into the market structure is provided by looking at the market shares of each individual supplier into the market. A complete set of figures and tables on market shares is provided in the electronic data. Figure 5 and Figure 6, provided as examples of these figures, show Summer Peak market share in the Portland destination market.

Figure 5 shows the market share of all suppliers with at least 1% of the Portland market (8 suppliers in all) with and without the RTO, assuming that the native load obligation remains. Figure 6 repeats this chart except that zero native load obligation is assumed. In both of these figures, BPA has the largest market share. The trading division of Pacific Gas & Electric, the PG&E National Energy Group, also has a noticeable share in the Portland market, reflecting the fact that PG&E has significant capacity, and aside from serving its own native load is analyzed here as its potential to serve only the Portland market. Note in Figure 5 that Portland General Electric (PGE) itself does not have any market share in the wholesale market when it is assumed to retain its full native load obligation. This demonstrates, for example, that PGE would import power to serve load above its historic native load level during the Summer Peak product market.

In general, the results convey the following points:

- Most destination markets in the RTO West region have HHIs that indicate a high degree of market concentration. This appears to result from the low overall regional electricity prices (see Table 26 and Table 27), rather than indicating high prices and market power. (See the charts in 'TCA RTO-West HHI by Region.pdf' and 'TCA RTO-West HHI by Scenario.pdf' in the electronic data for the summary of HHI values.)

- The companies listed below, which appear to behave as a single market according to the preliminary price clustering analysis, do in fact behave as a single market for many of the scenario's 12 product markets. For example, see Figure 7.

  - Avista
  - Bonneville Power Administration
  - NW Publics
  - Portland General Electric
  - Puget Sound Power and Light
  - Seattle City Light
  - Tacoma Power Utility

  However, for the scenarios in which there is assumed to be no native load obligation, these markets no longer behave as one market, as indicated by the different market concentration indices. (See the full set of charts in the electronic data.)

- In general, the native load assumption has a greater impact on market concentration and market share than does the implementation of the RTO and the associated changes in transmission rates.

- BPA has the dominant market share for most or all of the 12 product markets in most of the destination markets. See Table 28. (See also 'TCA RTO-West Market Share Summary Tables.xls'in the electronic data.)

- In a few destination markets, BPA is not the dominant supplier. The following companies have the dominant market share in their own, local destination market. Table 29 presents data for British Columbia. (See also 'Market Share Tables.xls' on the TCA web site.)

  - Bonneville Power Administration
  - British Columbia Hydro Authority
  - Nevada Power Company
  - Pacificorp East

Table 26: Threshold Prices - With RTO Case

Threshold Prices ($/MWh) in All Destination Markets – With RTO Case												
	Winter Super-Peak	Winter Peak	Winter Off-Peak	Spring Super-Peak	Spring Peak	Spring Off-Peak	Summer Super-Peak	Summer Peak	Summer Off-Peak	Autumn Super-Peak	Autumn Peak	Autumn Off-Peak
BC Hydro	82.13	52.55	37.19	36.75	32.87	31.27	32.31	30.42	30.05	44.98	43.42	36.99
Bonneville	59.33	40.58	33.45	32.56	30.30	26.99	36.26	31.95	26.08	46.27	43.99	37.30
Idaho Power Co	33.40	35.40	33.38	30.66	28.93	27.33	35.46	35.84	27.17	34.12	37.28	36.03
Montana Power Co	68.75	37.35	29.75	28.75	28.45	25.12	34.28	31.83	24.97	42.73	39.34	29.81
Nevada Power	42.12	31.96	28.22	34.31	33.26	27.53	45.99	42.74	28.96	37.95	36.02	29.56
NW Publics	43.75	39.55	33.55	33.47	30.15	27.08	33.86	31.04	26.25	44.16	41.47	36.70
Pacificorp—WY	56.14	34.85	28.60	33.50	30.16	25.41	45.64	35.63	27.09	40.70	38.29	29.90
Pacificorp—UT	51.78	32.22	26.10	33.38	30.24	24.43	44.00	34.91	25.49	36.61	34.18	26.74
Pacificorp West	64.72	39.38	33.62	31.21	29.72	27.03	46.81	35.65	28.83	46.03	44.05	37.25
Portland General Elec.	79.30	40.42	33.61	34.00	30.96	27.17	35.59	36.25	28.88	46.25	44.44	37.27
Puget Sound	56.55	39.39	33.52	33.02	32.11	27.19	41.98	32.03	28.42	46.62	45.18	37.54
Seattle City Light	56.18	39.89	33.61	33.31	31.10	27.15	31.90	30.97	29.41	46.92	44.55	37.26
Sierra Pacific	48.59	39.85	38.94	32.98	32.38	33.48	46.93	40.24	36.00	48.45	43.48	44.13
Tacoma Public Utilities	38.69	36.50	34.74	31.78	31.65	27.21	26.53	31.17	29.30	45.25	44.00	37.75
Avista	36.54	33.40	36.54	32.29	28.91	24.52	34.34	32.62	27.70	45.78	41.71	35.91

Table 27: Threshold Prices - With RTO

Threshold Prices ($/MWh) in All Destination Markets – Without RTO Case

	Winter Super-Peak	Winter Peak	Winter Off-Peak	Spring Super-Peak	Spring Peak	Spring Off-Peak	Summer Super-Peak	Summer Peak	Summer Off-Peak	Autumn Super-Peak	Autumn Peak	Autumn Off-Peak
BC Hydro	75.93	51.22	38.23	33.87	31.28	31.64	34.84	32.61	33.68	51.42	47.49	41.72
Bonneville	75.66	47.00	37.41	34.42	33.02	30.34	42.21	38.49	28.91	56.09	48.45	45.91
Idaho Power Co	28.44	39.14	33.86	33.10	32.88	29.30	38.44	42.38	27.57	40.72	40.87	39.22
Montana Power Co	79.38	37.31	27.65	26.47	28.25	24.22	30.92	36.28	22.00	44.17	38.63	30.37
Nevada Power	52.08	37.18	30.57	40.11	41.01	29.38	99.32	65.60	31.05	49.38	41.73	31.20
NW Publics	55.14	44.94	37.01	35.42	33.08	29.92	40.06	36.35	28.88	50.37	46.83	45.45
Pacificorp—WY	64.72	39.76	30.21	34.94	34.43	28.23	62.15	47.32	27.98	51.45	42.52	33.45
Pacificorp—UT	61.25	36.08	27.03	34.45	34.20	26.37	60.46	45.67	25.20	48.21	38.51	28.53
Pacificorp West	70.63	43.90	35.43	31.76	31.48	29.15	60.40	45.72	30.74	56.45	47.80	43.66
Portland General Elec.	86.01	45.83	35.60	31.25	31.73	28.64	41.57	46.23	30.06	55.64	47.49	43.03
Puget Sound	72.24	46.47	38.26	36.76	36.11	31.31	51.37	39.41	33.32	57.94	50.50	46.76
Seattle City Light	71.18	45.85	37.76	35.61	34.45	30.52	37.93	34.72	35.38	54.51	50.81	45.71
Sierra Pacific	62.61	47.74	43.42	45.79	40.53	39.88	80.34	51.36	42.14	54.64	55.58	46.58
Tacoma Public Utilities	41.27	41.27	38.87	35.22	34.78	30.13	31.36	35.58	34.38	52.81	49.06	45.73
Avista	42.70	37.78	42.23	35.88	32.56	29.13	42.08	40.42	31.41	52.80	51.31	44.02

Table 28: BPA Market Share - Without RTO

BPA Market Share in the All Destination Markets – Without RTO, 100% Native Load Obligation

Company	Winter Super-Peak	Winter Peak	Winter Off-Peak	Spring Super-Peak	Spring Peak	Spring Off-Peak	Summer Super-Peak	Summer Peak	Summer Off-Peak	Autumn Super-Peak	Autumn Peak	Autumn Off-Peak	Average
BCHA	37	27	47	32	32	50	27	24	47	34	28	23	34
BPA	65	64	66	79	78	71	78	78	72	67	65	41	69
IPC	49	25	34	43	38	33	31	26	39	24	23	18	32
MPC	68	73	72	81	79	90	82	81	91	74	74	46	76
NEVP	1	2	2	3	3	1	3	2	2	3	3	1	2
NWPUB	63	63	66	79	78	71	78	80	71	68	63	39	68
PACE-UT	9	11	12	11	10	10	11	10	12	9	10	5	10
PACE-WY	13	15	17	18	16	16	17	16	18	14	14	7	15
PACW	59	57	57	70	69	61	64	61	65	55	54	43	59
PGE	57	56	66	79	78	71	78	61	71	63	59	40	65
PSPL	64	64	65	78	77	71	78	78	71	67	65	40	68
SCL	64	63	65	78	77	71	78	79	68	67	64	40	68
SPP	35	40	38	41	35	36	35	31	38	28	27	23	34
TPU	67	65	65	79	78	71	80	79	70	69	65	40	69
WWPC	69	72	56	80	79	75	81	81	74	72	67	44	71

Table 29: Market Share in BC Hydro - With RTO, No NLO

Market Share in the BC Hydro Service Area – With RTO, No Native Load Obligation

Owner Name	Winter Super-Peak	Winter Peak	Winter Off-Peak	Spring Super-Peak	Spring Peak	Spring Off-Peak	Summer Super-Peak	Summer Peak	Summer Off-Peak	Autumn Super-Peak	Autumn Peak	Autumn Off-Peak	Average
British Columbia Hydro Authority	78.72	78.72	71.88	78.53	78.33	65.18	77.16	77.16	67.12	77.61	77.61	71.24	74.94
Bonneville Power Administration	8.96	8.98	10.48	9.43	9.68	13.74	10.46	10.52	12.96	9.17	9.19	9.38	10.25
Alberta	7.09	7.09	9.37	7.16	7.22	11.61	7.61	7.61	10.96	7.46	7.46	9.59	8.35
PG&E National Energy Group	1.25	1.25	2.27	1.24	1.27	2.70	1.33	1.34	2.75	1.49	1.49	2.61	1.75
Southern California Edison	0.52	0.54	0.87	0.47	0.48	1.03	0.48	0.49	1.04	0.67	0.61	0.98	0.68
Puget Sound Power and Light	0.59	0.59	0.74	0.41	0.40	0.81	0.38	0.39	0.70	0.59	0.57	0.75	0.58
Portland Gen and Electric	0.51	0.52	0.56	0.50	0.36	0.63	0.35	0.34	0.53	0.57	0.58	1.01	0.54
Seattle City Light	0.39	0.38	0.48	0.38	0.38	0.51	0.41	0.37	0.48	0.46	0.46	0.80	0.46
WAPA Upper Colorado	0.28	0.28	0.46	0.25	0.26	0.51	0.26	0.26	0.51	0.30	0.30	0.53	0.35
Idaho Power Company	0.23	0.23	0.30	0.23	0.24	0.39	0.25	0.24	0.43	0.28	0.27	0.47	0.30
Arizona Power Company	0.12	0.13	0.39	0.18	0.20	0.46	0.20	0.20	0.47	0.17	0.20	0.39	0.26
PacifiCorp East	0.16	0.16	0.33	0.16	0.16	0.37	0.16	0.16	0.35	0.17	0.18	0.31	0.22
Public Service Colorado	0.12	0.12	0.31	0.14	0.14	0.38	0.16	0.16	0.38	0.17	0.18	0.31	0.22
Montana Power Company	0.18	0.19	0.43	0.19	0.20	0.41	0.09	0.09	0.17	0.09	0.09	0.17	0.19
Sierra Pacific Power Company	0.15	0.15	0.26	0.15	0.10	0.23	0.10	0.11	0.22	0.18	0.18	0.32	0.18
PacifiCorp West	0.17	0.15	0.13	0.16	0.17	0.19	0.18	0.15	0.13	0.20	0.20	0.35	0.18
LA Dept. Water and Power	0.18	0.15	0.18	0.15	0.13	0.22	0.17	0.17	0.22	0.14	0.16	0.31	0.18
Salt River Project	0.05	0.05	0.13	0.07	0.07	0.16	0.08	0.08	0.17	0.07	0.08	0.15	0.10
Avista Utilities	0.11	0.10	0.13	0.06	0.06	0.13	0.03	0.03	0.05	0.04	0.04	0.05	0.07
Tucson Electric Power	0.02	0.02	0.07	0.03	0.03	0.08	0.04	0.04	0.08	0.03	0.04	0.07	0.05
San Diego Gas and Electric	0.05	0.05	0.04	0.02	0.02	0.05	0.02	0.02	0.05	0.03	0.02	0.04	0.03
Public Service New Mexico	0.01	0.01	0.05	0.01	0.02	0.07	0.02	0.02	0.07	0.01	0.01	0.03	0.03
Nevada Power Company	0.01	0.01	0.04	0.02	0.02	0.05	0.02	0.02	0.05	0.02	0.02	0.04	0.03
North West Publics	0.02	0.02	0.03	0.02	0.02	0.03	0.02	0.02	0.03	0.02	0.02	0.03	0.02
Empire District Electric Company	0.01	0.01	0.03	0.01	0.01	0.03	0.02	0.02	0.03	0.02	0.02	0.03	0.02
Imperial Irrigation District	0.02	0.01	0.03	0.01	0.01	0.03	0.01	0.01	0.03	0.02	0.02	0.03	0.02
WAPA Upper Missouri	0.07	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
WAPA Lower Colorado	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tacoma Public Utility	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HHI	**6331**	**6331**	**5372**	**6310**	**6284**	**4583**	**6124**	**6125**	**4803**	**6167**	**6167**	**5266**	**5822**

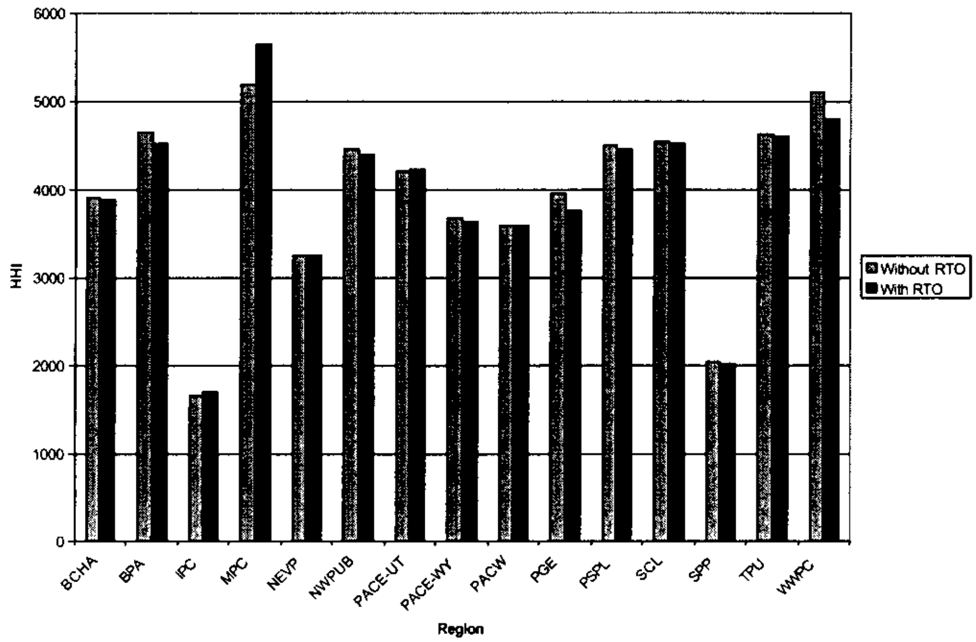


Figure 3: Average HHI, With and Without RTO, 100% NLO

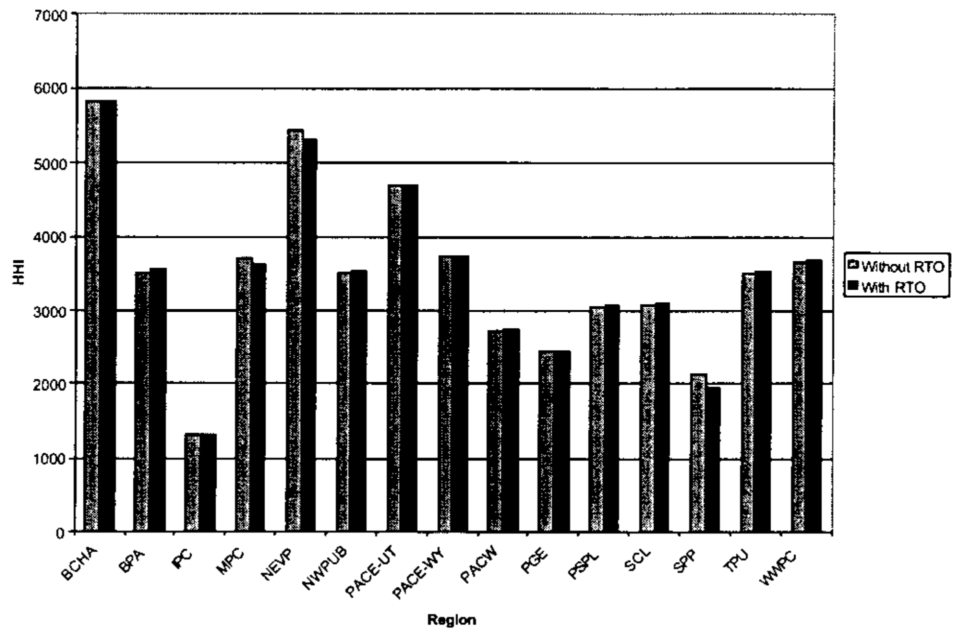


Figure 4: Average HHI, With and Without RTO, non NLO

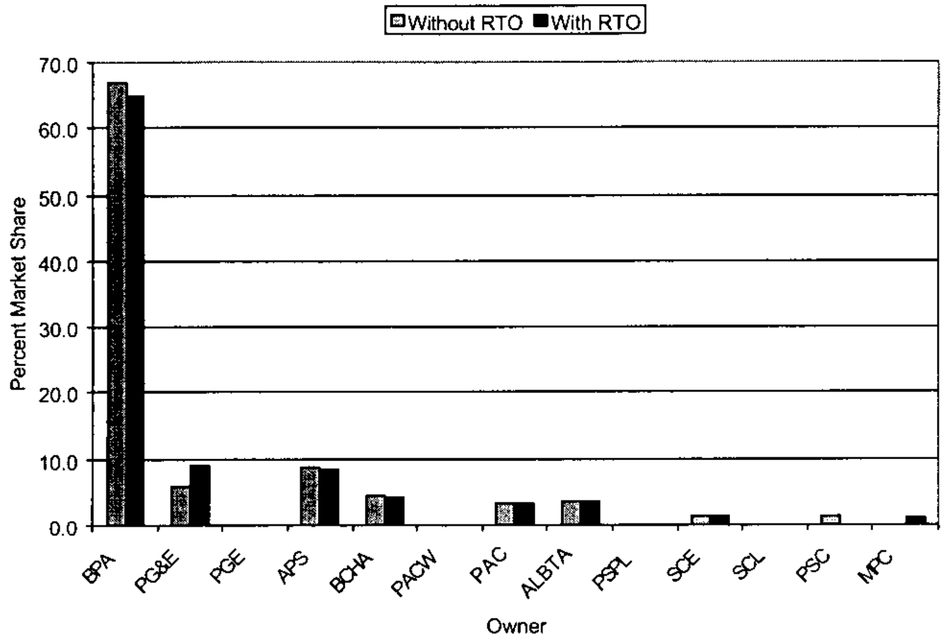


Figure 5: Summer Peak Share in Portland General Electric, With and Without RTO, 100% NLO

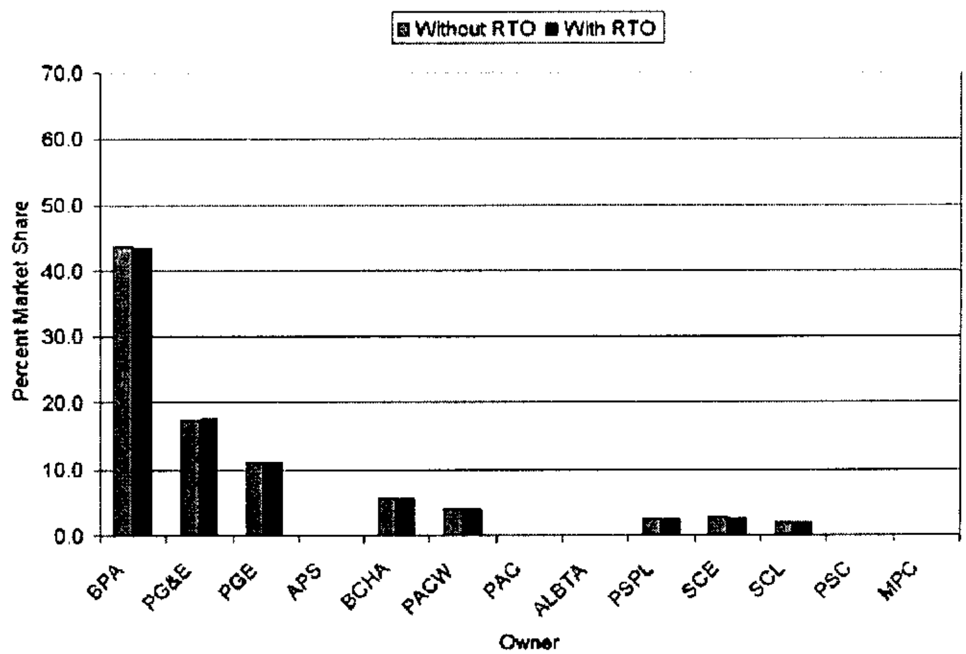
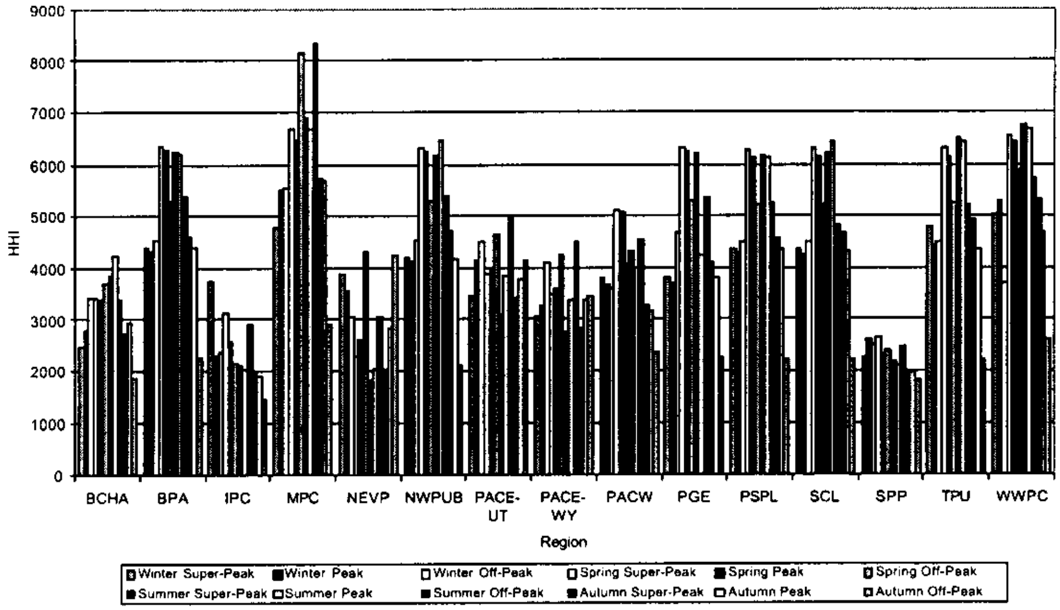
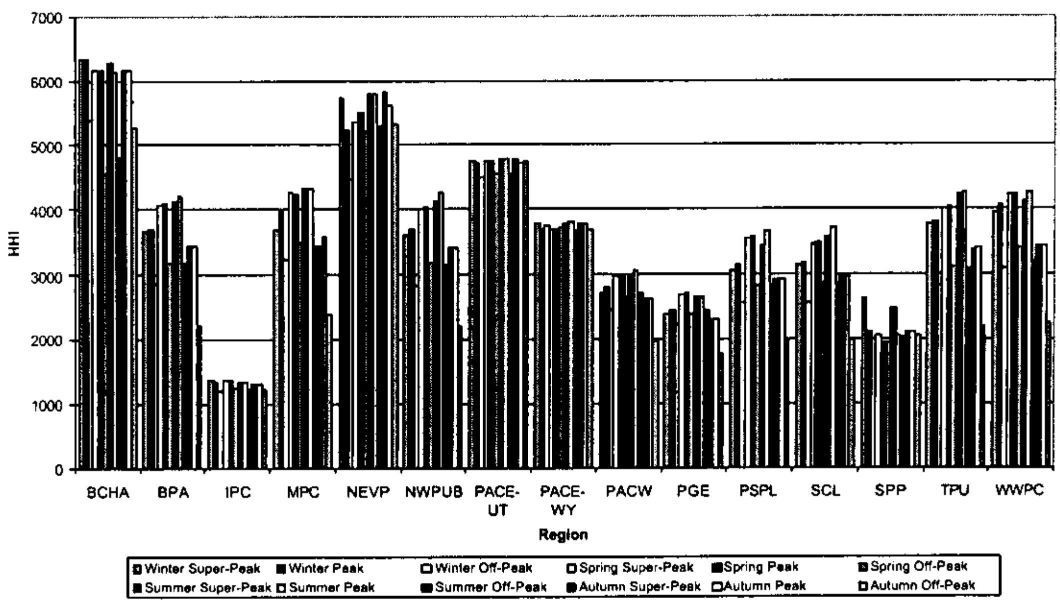


Figure 6: Summer Peak Share in Portland General Electric, With and Without RTO, no NLO



Full Native Load Obligation



No Native Load Obligation

Figure 7: HHI results for all seasons and load levels: Without RTO

7 Conclusion

The RTO West Benefit/Cost study, commissioned by northwest stakeholder group to further investigate the merits of RTO West, was reflected in this report. Methodology and assumptions directed by the work group are captured in this analysis, and results are presented.

The report shows benefits from an Energy Impact Analysis, both in the terms of production cost savings and from the benefits of consumer and producer surplus, also represented as a reduction in congestion rents. The results further seem robust, given the sensitivity analyses, to all but significant changes in the most fundamental drivers (pancaked rates and sharing of resources for reserves).

Costs of RTOs are captured through benchmarking, as are estimated costs of using secondary exchanges and schedule coordinator services. Finally many other impacts, predominantly found to be benefits, are presented qualitatively in this report.

Although the several study areas reported on here cannot necessarily be collapsed to produce a single conclusion on the quantitative merits of implementing RTO West, the magnitude of the potential savings reported in the Energy Impact Analysis, relative to the industry costs of RTOs, suggests that the benefits could outweigh the costs. The qualitative impacts—predominantly benefits—would tend to strengthen this conclusion. It is the northwest's producers and consumers, however, who must ultimately determine whether the sum of the quantifiable and unquantifiable benefits are greater than the economic and social costs.

Attachment 1: Input Assumptions

MEMORANDUM

TO: RTO West

FROM: Assef Zobian, Ellen Wolfe, Leslie Liu, Prashant Murti, Peter Capozzoli; Tabors Caramanis & Associates

RE: Western System Coordinating Council Modeling Inputs Assumptions

DATE: September 20, 2001 (Revised February 26, 2002)

This memo summarizes the inputs to the TCA locational price-forecasting mo del (GE MAPS) for the Western part of the USA and Canada (WSCC). For our market modeling and analysis, we used a full network transmission model including anticipated upgrades. The modeling was done for one year (2004) on an hourly basis and was carried out for two scenarios: status quo (base case) and the proposed RTO West. In both cases, a security-constrained least-cost unit commitment and dispatch assuming marginal cost bidding was performed.

As inputs to the model, TCA has compiled a complete database for the western electric power system based on public domain data sources including various FERC forms (Form 1, 714, 715), the WSCC EIA 411, the WSCC Path Rating Catalog, and the RTO West Benefit Cost Work Group. We have included in-house analysis to ensure data integrity, validity, and consistency of plant operations with market developments.

The following is a list of the major components of the model. The list is followed by a description of each component and the associated data sources.

(1) Load Inputs
(2) Thermal Unit Characteristics
(3) Planned Additions and Retirements
(4) Nuclear Unit Analysis
(5) Fuel Price Forecasts
(6) Transmission System Representation
(7) Environmental Regulations
(8) Conventional Hydro & Pump Storage Units
(9) External Region Supply Curves
(10) NUG Contracts
(11) Dispatchable Demand (Interruptible Load)

1. Load Inputs

Description: GE MAPS takes load inputs on an hourly basis (8760 per year) for each load-serving entity. GE MAPS manipulates the load profile in each year to account for the change in the day of the week at the start of the year. Loads were based on published data for annual energy in the year 2000. These values were then projected out to 2004 based on published growth rates for each load area for 2000–2004. Then the resulting 2004 energy values were factored upwards or downwards to match the sub-regional totals in the WSCC report. Peak load shape factors for each area were taken from the Aurora Model output as provided by RTO West. Finally, annual peaks were calculated using these factors together with annual energy for 2004. Load and energy for each area are listed in Appendix 1.

Data Sources: We used each company's FERC 714 filings and EIA-411 (Load and Capability) reports from the WSCC for both the actual 2000 hourly loads (in EEI format) and load forecasts (2000 submissions of 2000–2010 projections). We also used data provided to us by RTO West.

2. Thermal Unit Characteristics

Description: GE MAPS models generation units in detail, in order to accurately simulate their operational characteristics and thereby project realistic hourly prices. The following characteristics are modeled:

- Unit type (steam, combined-cycle, combustion turbine, cogeneration, etc.)
- Heat rate values and curve
- Summer and Winter Capacity
- Variable Operation and Maintenance costs
- Fixed Operation and Maintenance costs
- Forced and planned outage rates
- Minimum up and down times
- Quick start and spinning reserves capabilities
- Startup costs

When unit-specific data were unavailable, we developed heat rate curves for different units based on technology type and data points obtained from the data sources described below.

Data Sources: Our primary data source for generation characteristics was NERC's Electricity, Supply and Demand (ES&D) database, which contains unit type, fuel type (primary and secondary), capacity and heat rate data (until 1998).[69] We used NERC's Generation Availability Data System (GADS) database as a reference for forced and unforced outage rates, which bases outage rates on plant type, size, and vintage. We estimated operation and maintenance costs based on plant size, technology, and age, and supplemented our data with FERC Form 1 submissions, particularly for nuclear units.
Exhibits 1a and 1b show the generic data we use for all units in our database.

Exhibit 1a – Thermal Unit Characteristics

Unit Type	Size (MW)	FOM* ($/kW-yr)	VOM ($/MWh)	Minimum down time (hrs)	Minimum up time (hrs)	Heat rate Shape	Startup Btus (MBtu/ MW)
Combined Cycle		18	3	6	6	2 blocks, 50%@100% FLHR, 50%@100%	1
Combustion Turbine	<100	7	7	1	1	One Block	0
	>100	7	3.5	1	1	One Block	0
Steam Coal	<100	38	2	6	8	4 blocks, 50%@106% FLHR, 15%@90%, 30%@95%, 5%@100%	20
	<200	35	2	8	8	4 blocks, 50%@106% FLHR, 15%@90%, 30%@95%, 5%@100%	20
	>200	35	1	12	24	4 blocks, 50%@106% FLHR, 15%@90%, 30%@95%, 5%@100%	20
Steam Gas/Oil	<100	38	8	6	10	4 blocks, 25%@118% FLHR, 30%@90%, 35%@95%, 10%@103%	5
	<200	35	6	6	10	4 blocks, 25%@118% FLHR, 30%@90%, 35%@95%, 10%@103%	5
	>200	16	4	8	16	4 blocks, 25%@118% FLHR, 30%@90%, 35%@95%, 10%@103%	5
Steam Other		16	4	6	10	4 blocks, 25%@118% FLHR, 30%@90%, 35%@95%, 10%@103%	5
Nuclear		90	0	164	164	One Block	0
Geothermal		0	2	1	1	One Block	0
Wind/Solar		0	0	1	1	One Block	0

* FOM values include the following assumptions: $1.50/kW-yr for insurance and 10% of base FOM (before insurance) for capital improvements.

[69] In addition, we checked our data against the WSCC report entitled "Existing Generation and Significant Additions and Changes to System Facilities 2000 – 2010, Data as of January 1, 2001, Prepared by WSCC Technical Staff."

Exhibit 1b – Thermal Unit Characteristics, cont'd.

Type	Size (MW)	Quick Start (% of Capacity)	Spinning Reserve (% of Capacity)	Forced Outage Rate (% of Year)	Planned Outage Rate (% of Year)	Total Unavailability (% of Year)
Combined Cycle		0%	10%	1.5	6.82	8.32
Combustion Turbine	<100	100%	90%	4.34	5.21	9.55
	>100	100%	90%	2.53	7.5	10.03
Steam Coal	<100	0%	10%	2.96	9.48	12.44
	<200	0%	10%	3.46	8.66	12.12
	>200	0%	10%	4.51	9.79	14.3
Steam Oil/Gas	<100	0%	10%	2.14	7.91	10.05
	<200	0%	10%	4.64	10.95	15.59
	>200	0%	10%	4.01	12.04	16.05
Steam Other		0%	10%	3.09	7.27	10.36
Nuclear		0%	0%	9.03	11.35	20.38
Geothermal		0%	0%	2.22	8.18	10.4
Solar		0%	0%	70	0	70
Wind		0%	0%	50	0	50

3. Planned Additions and Retirements

Description: Planned entries and retirements impact the fuel mix of installed capacity and the composition of plants on the margin. Most retirements are oil or steam gas plants, which are likely to be replaced by combined-cycle gas plants. We entered new capacity in the model for the next few years based only on existing projects in development or projects in advanced stages of permitting, as indicated by environmental permit applications and internal knowledge.

We expect that new capacity will most likely take the form of either gas-fired combined-cycle (GTCC) or simple-cycle gas turbines (SCGT), based on the relative economics of their entry. Below are the capital cost, performance and financing assumptions we used for new entry:

Exhibit 2a – New Entry Assumptions (Real 2000$)

Cost Component	CCGT	SCGT
All-In Capital Cost ($/kW)	600–700	340–450
Debt:Equity Ratio	65:35	40:60
Return on Equity	16%	16%
Cost of Debt	8%	8%
Term of Debt	20 years*	20 years*
Fixed O&M ($/kW-yr)	15	5
Variable O&M ($/MWh)	2	3.5
Full Load Heat Rate (Btu/kWh)	6,900**	10,000
Standard Units Size S. (MW)	230	480
Standard Units Size W. (MW)	250	500
Forced Outage Rate	3%	4%
Planned Outage Rate	4%	3%

** After 2006 we assume the heat rate decreases to 6800 Btu/kWh.

Known new entries and retirements are summarized in Appendix 2. A capacity balance for the subregions of the WSCC is included in Appendix 3.

Data Sources: State Departments of Environmental Protection (DEP) were our primary source of planned projects that have a reasonably high degree of certainty. We also incorporated trade press announcements, power pool load and capacity reports, and internal knowledge in our analysis.

4. Nuclear Unit Analysis

Description: We used a combination of market knowledge, the Nuclear Regulatory Commission (NRC) watch list, and economic performance as reflected in model runs to determine whether any nuclear units should retire prior to their license expiration. We used a three-year (1995–1997) average of O&M costs and revenue projections from model runs to assess units' economic performance. We also incorporated maintenance schedules and current outages posted on the NRC website.

We also incorporated maintenance schedules and current outages posted on the NRC website. A fixed maintenance schedule is shown in Appendix 4.

Data Sources: *NRC*, trade press announcements, and FERC Form 1 data (for O&M costs).

5. Fuel Price Forecasts

Description: GE MAPS takes monthly fuel prices for all plants. We modeled fuel-switching capability and the seasonality of gas prices in order to accurately simulate dispatch behavior. Our fundamental assumption of bidding behavior in competitive energy markets is that generators will bid in their *marginal cost*. In the case of gas, this is the opportunity cost of fuel purchased (in addition to variable O&M and environmental adders), or the spot price of gas at the closest location to the plant. We therefore used forecasts of spot prices at regional hubs, and further refined these based on historical differentials between price points around each hub. For oil and coal we used estimates of the price delivered to generators on a regional basis. For residual oil, we applied our own price differential between prices of residual oils of different sulfur content.

Actual proposed fuel prices are contained under a separate attachment.

6. Transmission System Representation

Description: We used a full transmission system representation including transformers, AC and DC lines, phase shifters and buses, and modified by RT O West to include planned upgrades expected between now and 2004. Every unit and load was mapped electrically, and flow limits were defined for interfaces. These limits varied seasonally as specified by RTO West. For DC interties, the historical maintenance schedule for 2001 was used, and wheeling charges were based on current rates. Dispatch was subject to flow constraints, and flow limits on lines, interfaces, and binding constraints were monitored.

All monitored constraints have hard limits, i.e., very high overload costs, and MAPS re-dispatches resources to meet the limits. In addition, there are seasonal limits with minimum, average, and maximum Total Transfer Capabilities. These limits were used when they differed from the 2001 Path Rating Catalog. The minimum limits were assigned low overload cost, which allows MAPS to exceed this minimum limit if there is large price differential, or high congestion cost (higher than the assigned overload cost). Similarly, the average limits were assigned intermediate cost, which allowed MAPS to exceed the limit if the congestion cost was higher than the assigned overload cost.

All major transmission projects proposed for WSCC with an on-line date before summer 2004 were included in this study (starting with the WGA load flow case for 2004). The following is a list of some of these projects:

- Path 15 upgrade
- Falcon to Gonder 345 kV project
- Centennial Transmission (SNV)

Transmission nomograms
We added the following Nomograms to capture the relation on transfer limits on dependent interfaces:

- Path 15 (Midway Los Banos)/Path 17 (Borah West) was provided by BPA
- Path 20 (Path "C") was provided by PacifiCorp
- Southern California Import Total (SCIT) from the CAISO website.

For a listing of constraints, interfaces, seasonal ratings, transmission nomograms, and contract path limits, see Appendix 5.

Data Sources: We identified and monitor potentially binding lines and interfaces as listed in the 2000 WSCC Path Rating Catalog and FERC 715 filings. In addition we increased transfer capability over those interfaces where we believed transmission upgrades would be added. We used the contract path limits that were used in the report "Conceptual Plans for Electricity Transmission in the West, Report to the Western Governors' Association," August 2001.

7. Environmental Regulations

Description: We also added VOM values associated with scrubbers (SOx reduction) to units that already installed such equipment and incorporated these VOM values in the marginal cost bids. Further, we added to the marginal cost bids the opportunity cost of SOx tradable permits for all units, based on their current emission rates, and current allowance trading prices. We assumed the cost of SOx tradable permits to be $200/ton of sulfur emission. Exhibit 3 shows the units in New Mexico that have environmental controls and the associated cost adders for these controls.

We did not include tradable permit costs for NOx in the marginal cost.

The Western Regional Air Partnership (WRAP) is a voluntary, regional collaboration of the Western states and tribal commissions to implement the recommendations of the Grand Canyon Visibility Transport Commission to reduce haze in the Grand Canyon. Although WRAP does not have any enforced air quality regulations related to SOx and NOx, they may consider the implementation of market-based initiatives to reduce haze in the future. For units with emission control technology, we added the VOM and FOM associated with these technologies based on EPA estimates.

Exhibit 3 – Illustrative Example: New Mexico Units with Environmental Controls

Plant Name	Unit ID	Boiler Type	Primary Fuel	SO2 Controls	NOx Controls	1998 SO2 (tons)	1998 CO2 (tons)	1998 NOx (lb/MM Btu)	1998 NOx (tons)	1998 HI (MMBtu)	Winter Capacity	Sulfur VOM (1998$/ MWh)	NOx VOM Adder (1998$/ MWh)
Four Corners	1	DB	C	WL	U	3,892	1,595,729	0.73	5,932	15,557,071	170	1	0
Four Corners	2	DB	C	WL	U	3,490	1,418,913	0.71	5,088	13,831,877	170	1	0
Four Corners	3	DB	C	WL	LNB	4,052	1,884,357	0.53	5,001	18,367,014	220	1	0.05
Four Corners	4	CB	C	WL	LNB	13,990	6,096,320	0.5	15,064	59,434,485	740	1	0.07
Four Corners	5	DB	C	WL	LNB	14,566	5,885,703	0.51	14,840	57,369,768	740	1	0.05
San Juan	1	DB	C	O	LNB	7,780	2,758,988	0.43	5,882	26,901,261	316	1	0.05
San Juan	2	DB	C	O	OFA	6,472	3,182,392	0.51	8,076	31,024,998	312	1	0
San Juan	3	DB	C	O	LNB	11,055	3,660,446	0.42	7,658	35,668,634	488	1	0.05
San Juan	4	DB	C	O	LNB	14,655	4,682,946	0.43	9,885	45,648,125	498	1	0.05

Data Sources: NOx and SOx emission rates were obtained from the "EPA Emissions Scorecard for 2000, Appendix B," on a unit-by-unit basis.

8. Conventional Hydro and Pump Storage Units

Description: GE MAPS has special provisions for modeling hydro units. Since hydro generation is a major component in WSCC, special attention was given to the modeling. The model considers all environmental and operating constraints, such as maximum and minimum river flows. We used historical seasonal patterns for each individual hydro unit as a proxy for future seasonal generation (monthly GWh). Also using historical data, we developed three scenarios of hydro conditions: a wet year, a dry year, and a median year.

We used the hourly hydro generation schedule for pondage units in the Pacific Northwest and British Columbia as provided to us by RTO West. GE MAPS takes this hourly schedule as an input and does not schedule the units otherwise. Other pondage and pumped storage units are scheduled based on published data. Monthly maximum and minimum generation and total energy are supplied GE MAPS, and GE MAPS schedules the units to meet these requirements and shave peak loads. Total monthly hydro energy by load areas appears in Appendix 6.

Data Sources: The ES&D database was used for unit capacities, and the EIA 759 and 860 (1992–1998) was used for historical monthly generation (GWh). In addition, we checked our data against the WSCC report entitled "Existing Generation and Significant Additions and Changes to System Facilities 2000–2010, Data as of January 1, 2001, Prepared by WSCC Technical Staff."

9. External Regional Supply Curves

Description: The connection to the eastern grid is modeled as a series of thermal units and load buses depending on the direction of the flow. The thermal capacities of these representative units are determined by the maximum export capability across tie lines. We used historical exports, combined with our expectation of future conditions in these areas, to project export levels and prices for each of the forecast years.

We modeled the DC links as imports and exports depending on price at their location. If the price was below \$30/MWh, they exported to the eastern interconnect and ERCOT at full capacity. If the price was greater than \$30/MWh, but less than \$35/MWh, they exported at 50% of their capacity. For prices between \$35/MWh and \$40/MWh, there were zero exports. For prices between \$40/MWh and \$45/MWh, they imported at 50% of their capacity, and if the locational price exceeded \$45/MWh, they imported at 100% of capacity. These units were modeled as multi-block thermal units with total capacity twice the capacity of the link. A list of all DC links connecting the WSCC to the eastern part of the US and Canada is shown in Exhibit 4 below.

Exhibit 4 – External DC Links to the Eastern Inter-connect

DC Link	Company	State	Summer Capacity (MW)	Winter Capacity (MW)
Artesia	El Paso	NM	200	200
Blackwater	Pub Svc NM	NM	220	220
McNeil	Alberta	AB	150	150
Miles City	Basin Electric	MT	200	200
Virginia Smith	Basin Electric	NE	200	200
Stegal	Basin Electric	NE	110	110

10. NUG Contracts

Description: There is no significant NUG capacity in the West except in California. If we believe that the same process of contract negotiation that occurred in the east will occur in the west, then it is reasonable to assume that all these units will be dispatchable by 2003. However, most of the NUG capacity available is in the form of co-generation units, and we assume that the steam generated by the unit is required. Therefore, although the NUG units are made dispatchable in 2003, we used a low heat rate of 6000 Btu/kWh, thus ensuring that these units will always run even when they are dispatchable. We believe that contracts recently signed by the California Department of Water Resources will not distort the economics of generation in the west in general and in California in particular. From the EIA 860 B database we found that most of the large NUGs have stream output, so we kept their heat rates. For small NUGs, which were aggregated, we could not match all units, so we decided to increase the heat rate of some of them (approximately half) to 10,000 Btu/kWh. Exhibit 5 below shows the NUG capacity by state.

Exhibit 5 – NUG Capacity by State

Area	Capacity (MW)
Alberta	55
British Columbia	160
Arizona	50
California	7,237
Colorado	605
Idaho	99
Montana	104
Nevada	609
New Mexico	0
Oregon	542
Utah	53
Washington	678
Wyoming	45

11. Dispatchable Demand (Interruptible Load)

Description: We included in our modeling a representation of interruptible load to capture the effects on electricity prices. The presence of demand response is important to the energy and installed capacity prices. In the energy market, the value of energy to interruptible load caps the prices. The capacity of interruptible load works as installed reserves and lowers the capacity value. The size of interruptible load was determined as a percentage of total load for each region of the WSCC, and this percentage was applied to all load areas in the region. Dispatchable demand units were modeled as generators with a dispatch price of $400/MWh for the first block (50% of the company's dispatchable demand), and $8000/MWh for the second block.

In addition, we modeled aluminum smelters as interruptible non-conforming loads and assumed that they would be interrupted if the spot price of electricity exceeded $100/MWh. They did not have an hourly load shape and were modeled using dummy generators that turned on the quantity of the load once the price reached the requisite level.

Data Sources: We used interruptible load values based on the "Summary of Estimated Loads and Resources, Data as of January 1, 2001, Prepared by WSCC Technical Staff," as shown in Exhibit 6. Aluminum smelter information was based on our research.

Exhibit 6 – Interruptible Load Capacity (MW) by Region

WSCC Interruptible Demand by Region and Year																
Pool	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
ALBERTA	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220
AZNM-SNV	791	326	341	347	350	353	357	360	361	363	365	367	369	371	373	375
BRITCOL	305	305	305	305	305	305	305	305	305	305	305	305	305	305	305	305
CA-MX	960	996	400	400	400	400	400	400	400	400	400	400	400	400	400	400
NWPP-US	331	331	331	331	331	331	331	331	331	331	331	331	331	331	331	331
RMPA	118	118	118	119	119	119	120	120	120	121	121	121	121	121	121	121

Appendix 1

WSCC Load Forecast for 2004

Region	Load Area	Peak Load (MW)	Annual Energy (TWh)
BRITCOL	BC Hydro + W Kootenay	11,043	63,477
RTO West	Avista Corp	1,858	12,485
RTO West	Bonneville Power Admin	10,937	68,402
RTO West	Chelan Douglas Grant PUD	1,026	6,546
RTO West	Idaho Power Company	3,112	18,485
RTO West	Montana Power Company	1,187	7,748
RTO West	Nevada Power Company	5,261	20,971
RTO West	Pacificorp East	6,463	39,818
RTO West	Pacificorp West	4,296	26,150
RTO West	Portland General Electric	4,104	24,981
RTO West	Puget Sound Energy	4,254	24,999
RTO West	Seattle City Light	1,851	10,879
RTO West	Sierra Pacific Power	1,603	11,306
RTO West	Tacoma Public Utilities Light	1,434	8,428
ALBERTA	Alberta Power	8,333	57,278
CA-MX	LA Dept of Water & Power	5,803	31,691
CA-MX	Pacific Gas & Electric	28,305	138,101
CA-MX	San Diego Gas & Electric	4,032	22,020
CA-MX	Southern California Edison	19,429	106,109
Rocky Mtn	Public Service of Colorado	5,784	33,844
Rocky Mtn	WAPA Colorado-Missouri	3,375	20,624
Rocky Mtn	WAPA Upper Missouri	130	733
W Connect	Arizona Public Service Co	6,521	31,817
W Connect	El Paso Electric	1,105	7,782
W Connect	Imperial Irrigation District	816	3,922
W Connect	Public Service New Mexico	1,739	12,248
W Connect	Salt River Project	5,966	29,109
W Connect	Tucson Electric Power	2,312	11,279
W Connect	WAPA Lower Colorado	1,537	7,498

Appendix 2

New Entry Units in Alberta

Area	Year	Full Name	State	Type	Install Date	Capacity	Heat Rate
ALBERTA	2001	Poplar Creek Ph 2	AB	CCg	Jan-2001	70	6,900
		Edmonton Cogen	AB	CG	Apr-2001	25	6,800
		Carseland Cogen [Transcanada]	AB	CG	Jul-2001	81	6,000
		Redwater Cogen [Transcanada]	AB	CG	Jul-2001	42	6,000
		Vision Quest I	AB	WND	Jul-2001	3	1
		Balzac Cogen [PanCanadian]	AB	CG	Dec-2001	103	6,000
		Cavalier Cogen [PanCanadian]	AB	CG	Dec-2001	104	6,000
		Sturgeon 3, Valleyview AB	AB	GTg	Dec-2001	92	10,000
		Vision Quest II	AB	WND	Dec-2001	24	1
	2002	Rainbow Lake II	AB	CCg	Jan-2002	46	6,900
		Oldman	AB	Pondage	Mar-2002		
		ATCO Power Oil Sands (Energen)	AB	CTg	May-2002	25	10,000
		Muskeg River	AB	CCg	Oct-2002	171	6,900
		Shell Scotford	AB	GTg	Oct-2002	160	10,000
		Calgary Energy Centre [Calpine](DF)	AB	CTg	Dec-2002	50	10,000
	2003	Calgary Energy Centre [Calpine]	AB	CCg	Dec-2003	250	6,900
	2004	AES Calgary CC (A,B,C)	AB	CCg	Jan-2004	525	6,900

New Entry Units in Arizona/New Mexico/Southern Nevada and in British Columbia

Area	Year	Full Name	State	Type	Install Date	Capacity	Heat Rate
AZNM-SNV	2001	Desert Basin	AZ	CCg	Jun-2001	510	6,900
		Naniwa (TRI Center)	NV	CTg	Jun-2001	360	10,000
		South Point	AZ	CCg	Jun-2001	540	6,900
		Tucson CT1	AZ	CTg	Jun-2001	75	10,000
		West Phoenix CC 4	AZ	CCg	Jun-2001	121	6,900
		Griffith Energy CC1	AZ	CCg	Jul-2001	595	6,900
		Tucson CT2	AZ	CTg	Aug-2001	21	10,000
		Rye Patch	NV	GEO	Oct-2001	12	10,000
	2002	Redhawk CC 1&2	AZ	CCg	Mar-2002	1000	6,900
		Kyrene 7A	AZ	CCg	May-2002	250	6,900
		Arlington Valley	AZ	CCg	Jun-2002	500	6,900
	2002	Arlington Valley (DF)	AZ	CTg	Jun-2002	30	10,000
		Redhawk (DF)	AZ	CTg	Jun-2002	36	10,000
		West Phoenix CC 5	AZ	CCg	Jun-2002	500	6,900
		Panda Gila River CC1 (A-B)	AZ	CCg	Aug-2002	500	6,900
		Panda Gila River CC2 (A-B)	AZ	CCg	Aug-2002	500	6,900
		Las Vegas Cogen II	NV	CCg	Sep-2002	230	6,900
		Sempra Mesquite	AZ	CCg	Nov-2002	1000	6,900
		Sempra Mesquite (DF)	AZ	CTg	Nov-2002	140	10,000
	2003	Apex Industrial I	NV	CCg	Mar-2003	550	6,900
		Duke (Deming Power Plant)	NM	CTg	Jun-2003	506	10,000
		Harquahala Valley	AZ	CCg	Jun-2003	1000	6,900
	2004	Apex Industrial II	NV	CCg	May-2004	550	6,900

Area	Year	Full Name	State	Type	Install Date	Capacity	Heat Rate
BRITCOL	2001	Island Cogen 1	BC	CG	Feb-2001	240	6,000
		Burrard Thermal 1	BC	STg	Jun-2001	150	6,900
	2002	Arrow Lakes	BC	Pondage	Apr-2002	170	
		Pingston	BC	Pondage	Jul-2002	30	
	2004	Brilliant Upgrade	BC	Pondage	Jun-2004	20	

New Entry Units in California

Area	Year	Full Name	State	Type	Install Date	Capacity	Heat Rate
CA	2001	Mountain View Wind	CA	WND	Apr-2001	50	1
		3,5/01 Small Plant Aggregate (<100 MW)	CA	CTg	May-2001	19	10,000
		McClellan Upgrade	CA	CTgo	May-2001	22	10,000
		Chowchilla Peaker	CA	CTg	Jun-2001	49	10,000
		Fresno GT 1	CA	CTg	Jun-2001	18	10,000
		Harbor Generating Station (GT1-5)	CA	CTg	Jun-2001	240	10,000
		King City (Calpine)	CA	CTg	Jun-2001	50	10,000
		Procter & Gamble CG	CA	CTg	Jun-2001	44	10,000
		Valley GT1	CA	CTg	Jun-2001	48	10,000
		6,7/01 Small Plant Aggregate (<100 MW)	CA	GTg	Jul-2001	365	10,000
		Huntington Beach 3-4	CA	CCg	Jul-2001	450	6,900
		Los Banos Peaker	CA	CTg	Jul-2001	45	10,000
		Los Medanos Energy Center CC1 (Pittsburg District)	CA	CCg	Jul-2001	540	6,900
		Sunrise 1	CA	CCg	Jul-2001	320	6,000
		Sutter Power CC 1(A-C)	CA	CCg	Jul-2001	500	6,900
		Larkspur (Wildflower)	CA	CTgo	Jul-2001	90	10,000
		Indigo Energy Facility (1-3)	CA	CTg	Jul-2001	124	10,000
		Alliance Peaker Colton 1	CA	CTg	Aug-2001	40	10,000
		Alliance Peaker Colton 2	CA	CTg	Aug-2001	40	10,000
		Escondido GT2 (Calpeak Ent. #7)	CA	CTg	Aug-2001	49	10,000

New Entry Units in California, cont'd.

Area	Year	Full Name	State	Type	Install Date	Capacity	Heat Rate
CA	2001	Red Bluff	CA	CTg	Aug-2001	47	10,000
		Drews	CA	CTg	Aug-2001	40	10,000
		8,9/01 Small Plant Aggregate (<100 MW)	CA	GTg	Sep-2001	437	10,000
		Calpeak Border	CA	CTg	Sep-2001	49.5	10,000
		Gilroy 1 - 3 (Calpine)	CA	CTg	Sep-2001	135	10,000
		Century	CA	CTg	Sep-2001	40	10,000
		La Paloma CC 1	CA	CCg	Nov-2001	262	6,900
		La Paloma CC 2	CA	CCg	Nov-2001	262	6,900
		La Paloma CC 3	CA	CCg	Nov-2001	262	6,900
		La Paloma CC 4	CA	CCg	Nov-2001	262	6,900
		Vaca-Dixon	CA	CTg	Dec-2001	49	10,000
	2002	Otay Mesa CC 1-4	CA	CCg	May-2002	510	6,900
		Elk Hills CC1	CA	CCg	Jun-2002	500	6,900
		Moss Landing	CA	CCg	Jun-2002	975	6,900
		Delta Energy Center	CA	CCg	Jul-2002	880	6,900
	2003	Contra Costa	CA	CCg	Jan-2003	488	6,900
		Mountainview Power Project	CA	CCg	May-2003	972	6,900
		Blythe Energy	CA	CCg	Jun-2003	473.2	6,900
		High Desert	CA	CCg	Jun-2003	662	6,900
		Pastoria	CA	CCg	Jun-2003	690	6,900

New Entry Units in the Northwest and Rocky Mountain

Area	Year	Full Name	State	Type	Install Date	Capacity	Heat Rate
NWPP-US	2001	Gadsby (GT1-4)	UT	CTg	Jun-2001	100	10,000
		Klamath Falls	OR	CCg	Jun-2001	480	6,900
		Beaver 8	OR	CTg	Jul-2001	24	10,000
		Fredonia Addition	WA	CTgo	Aug-2001	106	10,000
		Mountain Home	ID	CTg	Oct-2001	90	10,000
		West Valley GT1-4	UT	CTg	Oct-2001	160	10,000
		Rathdrum Power CC 1 (COGENX)	ID	CCg	Nov-2001	265	6,900
		West Ridge	UT	CTg	Nov-2001	160	10,000
		Stateline Wind Project	OR	WND	Dec-2001	300	1
	2002	New Hydro 2	WA	Pondage	Jan-2002	500	
		Coyote Springs II (1&2)	OR	CCg	Jun-2002	42	6,900
		Frederickson	WA	CTgo	Jun-2002	249	10,000
		Big Hanaford (Centralia)	WA	STc	Jul-2002	248	12,000
		Hermiston CC (Umatilla)	OR	CCg	Jul-2002	550	6,900
		Goldendale CC	WA	CCg	Dec-2002	248	6,900
	2003	Satsop CC A&B	WA	CCg	Jan-2003	620	6,900

Area	Year	Full Name	State	Type	Install Date	Capacity	Heat Rate
RMPA	2001	Rawhide Diesels 1	CO	ICo	May-2001	40	15,000
		Fort Saint Vrain CC A&B, Platteville	CO	CCg	Jun-2001	235	6,900
		Fountain Valley / Midway [Enron]	CO	CTg	Jun-2001	240	10,000
		Valmont 8 [CO]	CO	CTg	Jun-2001	37	10,000
		Manchief 1&2	CO	CTg	Jul-2001	48	10,000
		Rock River	WY	WND	Oct-2001	50	1
		Brighton Station GT 1&2	CO	CTgo	Dec-2001	128	10,000
	2002	New CT-economic	CO	CTg	Jan-2002	250	10,000
		Plains End	CO	CTg	May-2002	108	11,000
		Limon Station GT 1&2 (TSGT)	CO	CTgo	Jun-2002	128	10,000
		Rawhide GT2	CO	CTg	Oct-2002	63	10,000
	2003	New CT-economic	CO	CTg	May-2003	250	10,000

Retired Units in the WSCC

Pool	Year	Full Name	State	Type	Date	Capacity	Heat Rate
CA-MX	2004	Haynes 3	CA	STgo	Dec-2004	222	9,219
		Haynes 4	CA	STgo	Dec-2004	222	9,603
RMPA	2001	Rawhide Diesels 1	CO	ICo	Oct-2001	40	15,000
	2003	Greeley Energy	CO	CG	Aug-2003	69	6,001

Appendix 3

Capacity Balance in the WSCC

Pool	Category	2001	2002	2003	2004
ALBERTA	Total Internal Demand	8,124	8,337	8,525	8,686
	Interruptible Demand	220	220	220	220
	Net Internal Demand	7,904	8,117	8,305	8,466
	Reserve Margin %	18	18	18	18
	Load + Reserve	9,327	9,578	9,800	9,990
	Firm Transfer	200	200	200	200
	EIA411 Capacity	8,708	9,024	8,780	8,781
	New Entry	544	452	250	525
	Retirement	0	0	0	0
	MAPS Capacity	9,686	10,125	10,375	10,900
	Balance	559	747	775	1,110
AZNM-SNV	Total Internal Demand	22,918	23,774	24,572	25,284
	Interruptible Demand	326	341	347	350
	Net Internal Demand	22,592	23,433	24,225	24,934
	Reserve Margin %	16	16	16	16
	Load + Reserve	26,207	27,182	28,101	28,923
	Firm Transfer	350	86	22	-12
	EIA411 Capacity	19,336	19,494	19,718	20,012
	New Entry	2,234	4,686	2,056	550
	Retirement	0	0	0	0
	MAPS Capacity	24,082	28,768	30,824	31,374
	Balance	-1,775	1,672	2,745	2,439
BRITCOL	Total Internal Demand	10,512	10,787	11,031	11,240
	Interruptible Demand	305	305	305	305
	Net Internal Demand	10,207	10,482	10,726	10,935
	Reserve Margin %	18	18	18	18
	Load + Reserve	12,044	12,369	12,657	12,903
	Firm Transfer	496	485	361	895
	EIA411 Capacity	10,715	11,104	10,803	10,805
	New Entry	390	200	0	20
	Retirement	0	0	0	0
	MAPS Capacity	12,872	13,072	14,072	13,092
	Balance	1,324	1,188	1,776	1,084

Capacity Balance in the WSCC, cont'd.

Pool	Category	2001	2002	2003	2004
CA-MX	Total Internal Demand	53,895	54,880	55,890	56,948
	Interruptible Demand	996	400	400	400
	Net Internal Demand	52,899	54,480	55,490	56,548
	Reserve Margin %	16	16	16	16
	Load + Reserve	61,363	63,197	64,368	65,596
	Firm Transfer	2,086	2,186	2,195	2,087
	EIA411 Capacity	54,567	55,226	55,272	55,274
	New Entry	4,948	2,865	3,285	0
	Retirement	0	0	0	444
	MAPS Capacity	59,303	62,168	65,453	65,453
	Balance	26	1,157	3,280	1,944
NWPP-US	Total Internal Demand	40,224	40,846	41,478	42,120
	Interruptible Demand	331	331	331	331
	Net Internal Demand	39,893	40,515	41,147	41,789
	Reserve Margin %	16	16	16	16
	Load + Reserve	46,276	46,997	47,731	48,475
	Firm Transfer	843	843	843	843
	EIA411 Capacity	52,492	52,986	53,494	53,494
	New Entry	1,685	1,837	620	0
	Retirement	0	0	0	0
	MAPS Capacity	55,611	57,498	58,118	58,118
	Balance	10,178	11,344	11,230	10,486
RMPA	Total Internal Demand	8,516	8,781	9,057	9,274
	Interruptible Demand	118	118	119	119
	Net Internal Demand	8,398	8,663	8,938	9,155
	Reserve Margin %	16	16	16	16
	Load + Reserve	9,742	10,049	10,368	10,620
	Firm Transfer	733	691	691	691
	EIA411 Capacity	10,784	10,805	11,006	11,208
	New Entry	778	549	250	0
	Retirement	40	0	69	0
	MAPS Capacity	12,488	12,997	13,247	13,178
	Balance	3,479	3,639	3,570	3,249

Appendix 4

Fixed Maintenance Schedule for WSCC Nuclear Units

Plant & Unit	Summer Capacity (MW)	Projected Forced Outage Rate	Projected Planned Outage Rate (Non-Refueling, Refueling Period)	Start Date for Refueling Outage										Outage Cycle Length (Months)
				2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	
Diablo Canyon1	1,073	6.0%	7.0%, 17.0%		23-Jan		23-Jan		23-Jan		23-Jan		23-Jan	24
Diablo Canyon2	1,087	6.0%	7.0%, 17.0%	4-Feb		4-Feb		4-Feb		4-Feb		4-Feb		24
Palo Verde1	1,258	6.0%	7.0%, 17.0%	31-Aug		1-Mar	31-Aug		2-Mar	31-Aug		2-Mar	1-Sep	18
Palo Verde2	1,258	6.0%	7.0%, 17.0%	13-Mar	12-Sep		13-Mar	12-Sep		13-Mar	12-Sep		14-Mar	18
Palo Verde3	1,262	6.0%	7.0%, 17.0%		8-Mar	6-Sep		8-Mar	7-Sep		8-Mar	7-Sep		18
San Onofre2	1,090	6.0%	7.0%, 17.0%	10-May		10-May		10-May		10-May		10-May		24
San Onofre3	1,080	6.0%	7.0%, 17.0%		18-Dec		18-Dec		18-Dec		18-Dec		18-Dec	24
WNP2	1,170	6.0%	7.0%, 17.0%	23-Apr		23-Apr		23-Apr		23-Apr		23-Apr		24

Appendix 5

Monitored Transmission Constraints from the WSCC 2001 Path Rating Catalog

Catalog Index	Constraint Name	Max Limit	Min Limit
1	Alberta-British Columbia	1000	–1200
2	- Back-to-back DC Converter -	-	-
3a	Northwest-Canada	2000	–3150
3b	Ing-Custer	2850	–2000
3c	BOUNDARY 230-NLYPHS 230- 1	400	–400
4	West of Cascades-North	9800	–9800
5	West of Cascades-South	7000	–7000
6	West of Hatwai	2800	–9999
7	- No constraint defined -	—	—
8	Montana to Northwest	2200	–2200
9	West of Broadview	2573	–9999
10	West of Colstrip	2598	–9999
11	West of Crossover	2598	–9999
12	Colstrip 500/230 kV Transf	500	–500
13	- No constraint defined -	—	—
14	Idaho to Northwest	2400	–1200
14a	Idaho-Northwest 500	1500	–9999
14b	Northwest-Idaho 230	1200	–1200
15	Midway - Los Banos	3600	–9999
16	Idaho-Sierra	500	–360
17	Borah West Actual	2307	–9999
18	Idaho - Montana	337	–337
19	Bridger West	2200	–9999
20	Path C Actual	1000	–1000
21	Arizona to California	5700	–9999
22	Southwest of Four Corners	2325	–9999
23	Four Corners 345/500	840	–840
24	PG&E - SPP	160	–150
25	Pacificorp/PG&E South	80	–30
26	Northern - Southern California	3000	–2400
27	- DC bi-pole -	—	—
28	Intermountain - Mona 345	1400	–1200
29	Intermountain - Gonder 230	200	–9999
30	TOT 1A Actual	650	–650
31	TOT 2A Actual	650	–650
32	Pavant/InterMt-Gonder Actual	245	–150
33	Bonanza-West Actual	735	–9999
34	- Replaced in 2001 PRC -	—	—
35	TOT 2C	300	–300
36	TOT 3 Actual	1250	–9999
37	TOT 4A	810	–9999

Catalog Index	Constraint Name	Max Limit	Min Limit
38	TOT 4B Actual	680	–9999
39	TOT 5 Actual	1675	–9999
40	TOT 7 Actual	890	–9999
41	Sylmar to SCE Actual	1200	–1200
42	2-FACE,COACHELV-MIRIID - 1	600	–9999
43	North of San Onofre Actual	2440	–9999
44	South of San Onofre	2200	–9999
45	California-CFE	408	–408
46	West of the Colorado R (WOR)	10118	–10118
47	NM1 Actual	925	–925
48	NM2 Actual	1692	–9999
49	East of Colo River (500–345)	7550	–9999
50	Cholla-Pinnacle Peak 345	1200	–9999
51	Southern Navajo	2264	–9999
52	Silver Peak-Control	17	–17
53	Billings-Yellowtail	400	–400
54	Coranado-Silverking-Kyrene	1100	–9999
55	Brownlee East Total	1560	–9999
55a	Brownlee East	1450	–9999
56	- Removed in 2001 PRC -	—	—
57	- No constraint defined -	—	—
58	ELDORADO- MEAD	1140	–1140
59	Eagle Mountain-Blythe 161 k	72	–72
60	Inyo-Control 115 kV	56	–56
61	LUGO 500-VICTORVL	900	–1950
62	Eldorado-McCullough 500 kV	2598	–2598
63	Perkins-Mead-Marketplace 50	1300	–9999
64	MARKETPLACE – ADELANTO	1200	–1200
65	- DC Intertie -	—	—
66	COI	4800	–3675
67–72	No limits defined	—	—
73	North of John Day	8400	–8400
74	No limit defined	—	—
75	Midpoint – Summer Lake	1500	–400
	Alberta North- South	1350	–9999

Individual Constraints from the WSCC 2001 Path Rating Catalog

Constraint Name	Max Limit	Min Limit
CRYSTAL 230-H ALLEN 230 1	950	-950
GOSHEN 345-GOSHEN 161 1	448	–448
BRADY 230-ANTLOPE 230 1	478	–478
MOENKOPI 500-FOURCO&2 500 1	1645	–1645
BICKNELL 345-VAIL 345 1	815	–815
CORONADO 345-SPRINGR 345 1	672	–672
GREEN-AE 230-GREEN-AE 345 1	150	–150
SAGUARO 500-TORTOLIT 500 0	672	–672
SOUTH 345-WESTWI&1 345 1	672	–672
SAGUARO 500-CHOLLA&2 500 1	888	–888
SILVERKG 500-CORONA&3 500 1	1732	–1732
MOENKOPI 500-NAVAJO&2 500 1	1482	–1482
MOENKOPI 500AFOURCO&2 500 1	1645	–1645
NAVAJO 500-MCCULLGH 500 1	1411	–1411
WESTWING 500-NAVAJO&4 500 1	1034	–1034
WESTWING 345-WESTWI&1 345 1	600	–600
HIDALGO 345-GREENLEE 345 0	717	–717
HATWAI 500-LOW GRAN 500 0	2182	–2182
COULEE 230-BELL BPA 230 3	414	–414
COULEE 230-BELL BPA 230 5	418	–418
COULEE 230-WEST 230 0	521	–521
COULEE 115-BELL BPA 115 0	155	–155
N LEWIST 115-DRY GH T 115 0	111	–111
HATWAI 230-LOLO 230 0	366	–366
LOLO 230-LOLO 115 1	125	–125
OXBOW 230-BROWNLEE 230 1	100	–100
OXBOW &3 230-LOLO 230- 1	478	–478
HELLSCYN 230-BROWNLEE 230 1	478	–478
MIDPOINT 345-MIDPOINT 230 1	500	–500
DIXONVLE 115-DIXONVLE 230 0	125	–125
HERNDON 230-KEARNEY 230 1	317	–317
MARTIN C 115-POTRERO 115 1	144	–144
MIDWAY 230-MIDWAY 500 1	1120	–1120
GATES 230-HENRETTA 230 1	753	–753
MC CALL 115-SANGER 115 1	224	–224
MONA 345-BONANZA 345- 1	650	–650
TRACY 500-LOSBANOS 500- 1	2122	–2122
TRACY 500-TESLA 500- 1	2122	–2122
BELLOTA 230-RNCHSECO 230- 1	488	–488

Constraint Name	Max Limit	Min Limit
BELLOTA 230-RNCHSECO 230- 2	488	–488
GOLDHILL 230-LAKE 230- 1	302	–302
COTWDPGE 230-COTWDWAP 230- 1	500	–500
TRACY 230-TESLA D 230- 1	333	–333
TRACY 230-TESLA D 230- 2	333	–333
GARRISON 500-GARRIS&1 500- 1	1732	–1732
GARRISON 500-GARRIS&3 500- 2	1732	–1732
NOXON 230-PINE CRK 230- 0	308	–308
RINALDI 230-OWENS 230 1	458	–458
CONTROL 115 INYOKERN 115 1	82	–82
CONTROL 115 INYOKERN 115 2	82	–82
INYO 230 OWENS 230 1	222	–222
CONTROL 230 OXBOW 230 1	183	–183
INYOKERN-KRAMER 115	165	–165
AMPS-PTRSNFLT	478	–478

Contract Path Ratings for the WSCC, 2004

Contract Path Name	Max Flows Export (MW)		Min Flows Import (MW)	
	Summer	Winter	Summer	Winter
ALBERTA -B.C.HYDR	1000	1000	-1200	-1200
ARIZONA -IMPERIAL	587	587	-387	-387
ARIZONA -LADWP	2761	2761	-1889	-1889
ARIZONA -NEW MEXI	2000	2000	-2000	-2000
ARIZONA -PACE	600	600	-590	-590
ARIZONA -SANDIEGO	1133	1133	-400	-400
ARIZONA -SOCALIF	3195	3195	-700	-700
ARIZONA -WAPA L.C	3739	3739	-5189	-5189
B.C.HYDR-NORTHWES	3150	3150	-2000	-2000
B.C.HYDR-W KOOTEN	588	588	-588	-588
IDAHO -NORTHWES	2400	2400	-1200	-1200
IDAHO -PACE	2100	2100	-1600	-1600
IDAHO -SIERRA	500	500	-360	-360
IMPERIAL-SANDIEGO	163	163	-163	-163
IMPERIAL-SOCALIF	600	600	-600	-600
LADWP -NEVADA	1620	1620	-1620	-1620
LADWP -NORTHWES	3100	3100	-3100	-3100
LADWP -PACE	1400	1400	-1920	-1920
LADWP -SIERRA	200	200	-200	-200
LADWP -SOCALIF	3400	3400	-3400	-3400
LADWP -WAPA L.C	1950	1950	-2120	-2120
MONTANA -NORTHWES	2200	2200	-600	-600
MONTANA -PACE	737	737	-737	-737
MONTANA -WAPA U.M	400	400	-400	-400
NEVADA -PACE	300	300	-300	-300
NEVADA -SOCALIF	637	637	-637	-637
NEVADA -WAPA L.C	1250	1250	-1250	-1250
NEW MEXI-PSCOLORA	224	224	-224	-224
NEW MEXI-WAPA L.C	700	700	-700	-700
NEW MEXI-WAPA R.M	600	600	-600	-600
NORTHWES-PG AND E	4880	4900	-3705	-3705
NORTHWES-SIERRA	300	300	-300	-300
NORTHWES-W KOOTEN	200	200	-200	-200
PACE -SIERRA	245	245	-150	-150
PACE -WAPA L.C	300	300	-300	-300
PACE -WAPA R.M	2370	2370	-2370	-2370
PG AND E-SIERRA	160	160	-160	-160
PG AND E-SOCALIF	3000	3000	-3000	-3000
PSCOLORA-WAPA R.M	2455	2455	-2392	-2392
SANDIEGO-OUTBACK	408	408	-408	-408
SANDIEGO-SOCALIF	200	200	-1800	-1800
SIERRA -SOCALIF	18	18	-18	-18
SOCALIF -WAPA L.C	1060	1060	-1060	-1060
WAPA L.C-WAPA R.M	400	400	-400	-400
WAPA U.M-WAPA R.M	300	300	-300	-300

Seasonal Operating Transfer Capabilities

PATH (WSCC path #)	2001 PATH RATING CAT. VALUE	Spring (April-May)				Summer (June-October)				Winter (November-March)			
		Approved Seasonal OTC 2001	Max OTC 2004	Mean OTC 2004	Min OTC 2004	Approved Seasonal OTC 2001	Max OTC 2004	Mean OTC 2004	Min OTC 2004	Approved Seasonal OTC 2001	Max OTC 2004	Mean OTC 2004	Min OTC 2004
COI (66)	4800 MW N-S 3675 MW S-N	4800 MW N-S 3675 MW S-N	4350 MW N-S 3675 MW S-N	4172 MW N-S 2840 MW S-N	2800 MW N-S 2450 MW S-N	4600 MW N-S 3675 MW S-N	4300 MW N-S 3675 MW S-N	4300 MW N-S 2949 MW S-N	2750 MW N-S 1908 MW S-N	4350 MW N-S 3675 MW S-N	4300 MW N-S 3675 MW S-N	4300 MW N-S 3485 MW S-N	2750 MW N-S 2000 MW S-N
PDCI (65)	3100 MW N-S 3100 MW S-N	3100 MW N-S 3100 MW S-N	3100 MW N-S 2084 MW S-N	2305 MW N-S 1549 MW S-N	0 MW N-S 0 MW S-N	2975 MW N-S 3100 MW S-N	2975 MW N-S 2200 MW S-N	2846 MW N-S 2043 MW S-N	0 MW N-S 0 MW S-N	2810 MW N-S 3100 MW S-N	2810 MW N-S 2200 MW S-N	2800 MW N-S 2032 MW S-N	0 MW N-S 0 MW S-N
North of John Day (73)	8400 MW N-S	8000 MW N-S	8000 MW N-S	7500 MW N-S	6500 MW N-S	8000 MW N-S	8000 MW N-S	7500 MW N-S	6500 MW N-S	7900 MW N-S	7900 MW N-S	7400 MW N-S	6500 MW N-S
North of Hanford	Not Rated		4300 MW N-S		3500 MW N-S		4300 MW N-S		3500 MW N-S		4300 MW N-S		3500 NW N-S
Cross Cascades North (4)	9800 MW N-S										9800 MW E-W		7500 MW E-W
Cross Cascades South (5)	7000 MW N-S										8200 MW E-W		6600 MW E-W
West of Coyote	Not Rated		4000 MW E-W		3100 MW E-W		4000 MW E-W		2900 MW E-W		4000 MW E-W		3100 MW E-W
South of Snoking	Not Rated		2700 MW N-S 2140 MW S-N		1700 MW N-S 1540 MW S-N		2700 MW N-S 2140 MW S-N		1700 MW N-S 1540 MW S-N		2700 MW N-S 2140 MW S-N		1700 MW N-S 1540 MW S-N
Raver-Paul	Not Rated		1820 MW N-S		1280 MW N-S		1820 MW N-S		1280 MW N-S		1820 MW N-S		1280 MW N-S
Keeler-Allston	Not Rated		1600 MW N-S		800 MW N-S		1600 MW N-S		800 MW N-S		1600 MW N-S		800 MW N-S
Alturas (76)	300 MW N-S 300 MW S-N	300 MW N-S 300 MW S-N	300 MW N-S 300 MW S-N		0 MW N-S 0 MW S-N	300 MW N-S 300 MW S-N	300 MW N-S 300 MW S-N		0 MW N-S 0 MW S-N	300 MW N-S 300 MW S-N	300 MW N-S 300 MW S-N		0 MW N-S 0 MW S-N
Sierra - Idaho (16)	500 MW N-S 360 MW S-N	500 MW N-S 262 MW S-N				500 MW N-S 262 MW S-N				500 MW N-S 262 MW S-N			
Sierra - PG&E (24)	160 MW E-W 160 MW W-E	120 MW E-W 100 MW W-E				120 MW E-W 100 MW W-E				120 MW E-W 100 MW W-E			
Sierra - Utah (32)	245 MW E-W 150 MW W-E	240 MW E-W 150 MW W-E				240 MW E-W 150 MW W-E				240 MW E-W 150 MW W-E			
Idaho - Northwest (18)	2400 MW E-W 1200 MW W-E	2400 MW E-W 1200 MW W-E	2400 MW E-W 1200 MW W-E		1200 MW E-W 800 MW W-E	2400 MW E-W 1200 MW W-E	2400 MW E-W 1200 MW W-E		1200 MW E-W 800 MW W-E	2400 MW E-W 1200 MW W-E	2400 MW E-W 1200 MW W-E		1200 MW E-W 800 MW W-E
Brownlee East (55)	1750 MW W-E	1750 MW W-E	1750 MW W-E		1560 MW W-E	1750 MW W-E	1750 MW W-E		1560 MW W-E	1750 MW W-E	1750 MW W-E		1560 MW W-E
Midpoint Summer Lake	1500 MW E-W Not Rated W-E	1500 MW E-W 400 MW W-E				1500 MW E-W 400 MW W-E				1500 MW E-W 400 MW W-E			
Bridger West	2200 MW E-W	2200 MW E-W				2200 MW E-W				2200 MW E-W			

Seasonal Operating Transfer Capabilities, cont'd.

PATH (WSCC path #)	2001 PATH RATING CAT. VALUE	Spring (April-May)				Summer (June-October)				Winter (November-March)			
		Approved Seasonal OTC 2001	Max OTC 2004	Mean OTC 2004	Min OTC 2004	Approved Seasonal OTC 2001	Max OTC 2004	Mean OTC 2004	Min OTC 2004	Approved Seasonal OTC 2001	Max OTC 2004	Mean OTC 2004	Min OTC 2004
Borah West (17)	2307 MW E-W	2273 MW E-W (heavy load) 2307 MW E-W (light load)				2100 MW E-W				2307 MW E-W			
Path C (20)	1000 MW N-S 1000 MW S-N	830 MW N-S 775 MW S-N (heavy	830 MW N-S 900 MW S-N		520 MW N-S 775 MW S-N	830 MW N-S 775 MW S-N (heavy	830 MW N-S 900 MW S-N		520 MW N-S 775 MW S-N	870 MW N-S 785 MW S-N (heavy	870 MW N-S 950 MW S-N		550 MW N-S 785 MW S-N
Alberta - BC (1)	1000 MW E-W 1200 MW W-E	1000 MW E-W 1200 MW W-E				1000 MW E-W 1200 MW W-E				1000 MW E-W 1200 MW W-E			
Northwest - Canada (3)	3150 MW N-S 2000 MW S-N	3150 MW N-S 2000 MW S-N	2800 MW N-S 2000 MW S-N	2075 MW N-S 1941 MW S-N	650 MW N-S 300 MW S-N	3150 MW N-S 2000 MW S-N	2800 MW N-S 2000 NW S-N	1898 MW N-S 1908 MW S-N	600 MW N-S 0 MW S-N	3150 MW N-S 2000 MW S-N	3150 MW N-S 2000 MW S-N	2522 MW N-S 1946 MW S-N	400 MW N-S 200 MW S-N
Montana - Northwest (8)	2200 MW E-W 600 MW W-E	2200 MW E-W 600 MW W-E	2175 MW E-W 1350 MW W-E	1983 MW E-W 1000 MW W-E	1750 MW E-W 600 MW W-E	2200 MW E-W 1350 MW W-E	2200 MW E-W 1350 MW W-E	1926 MW E-W 1000 MW W-E	955 MW E-W 600 MW W-E	2200 MW E-W 600 MW W-E	2200 MW E-W 1350 MW W-E	1990 MW E-W 1000 MW W-E	800 MW E-W 600 MW W-E
Montana - Idaho (18)	337 MW N-S 337 MW S-N	337 MW N-S 302 MW S-N				337 MW N-S 234 MW S-N				337 MW N-S 337 MW S-N			
West of Hatwai (6)	2800 E-W	2800 E-W	3600 MW E-W	3282 MW E-W	2100 MW E-W	2800 E-W	3600 MW E-W	3200 MW E-W	2100 MW E-W	2800 E-W	3600 MW E-W	3282 MW E-W	2100 MW E-W
Montana - Southeast	Not Rated	600 MW N-S 384-600 MW S-N	600 MW N-S 600 MW S-N		299 MW S-N	600 MW N-S 362-600 MW S-N	600 MW N-S 600 MW S-N		362 MW S-N	600 MW N-S 301-600 MW S-N	600 MW N-S 600 MW S-N		301 MW S-N

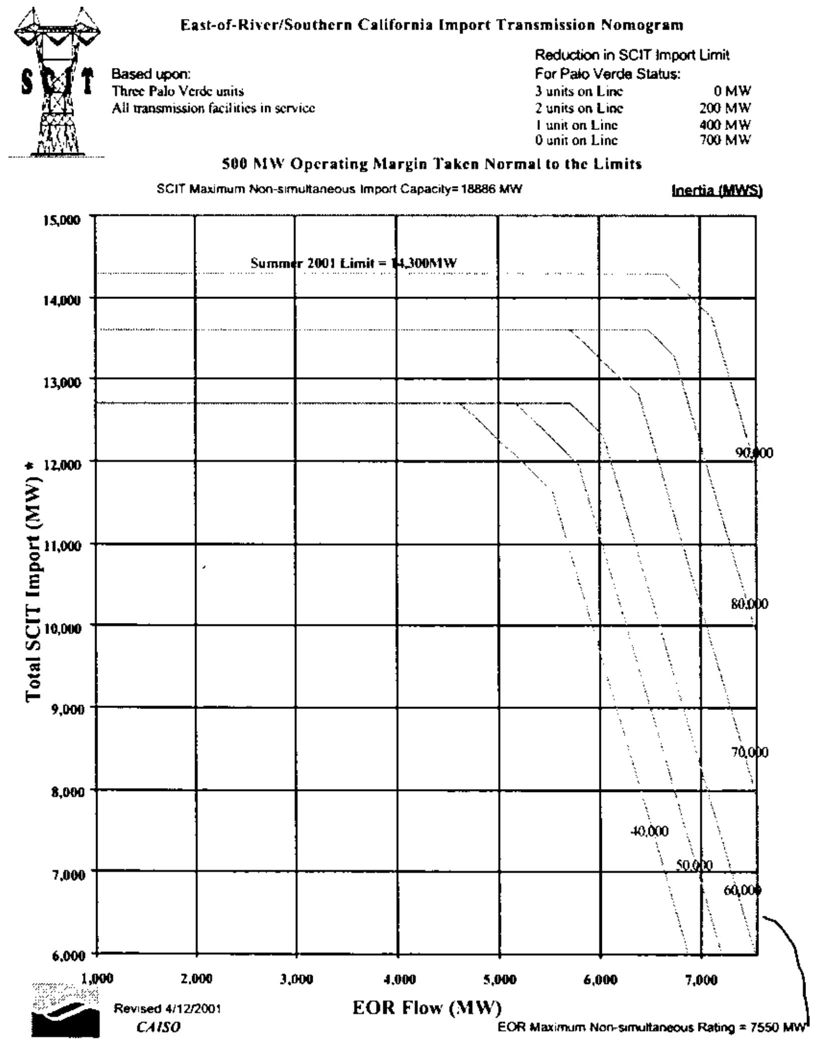
INFORMATION:

The seasonal OTC's are from NOPSG seasonal studies for the last year and adjusted to represent expected impacts from the G-9 projects. Notes below contain additional information. The approved seasonal OTC in

NOTES:

1. Max, Mean, Min OTC information in shaded rows provided by BPA.
2. Maximum seasonal OTC for COI is lower than seasonal OTC due to higher Northern California generation assumption.
3. The sum of the COI + Alturas schedules cannot exceed the COI OTC.
4. Actual Scheduling capability data for November 2000 - September 2001 was used for to define max, mean, & min OTC for COI, PDCI, NW-Canada, Montana-NW, and West of Hatwai.
5. PDCI is power order at the sending end (i.e., N-S flow at Celilo terminal, S-N at Sylmar terminal)
6. PDCI S-N limited to a maximum of 2200 MW due to lack of NW load tripping available for remedial action. May be limited further by West of Borah flow. PDCI limit is reduced 2 MW for every 1 MW the West o
7. Maximum, mean and minumums for North of John Day are based on engineering judgement.
8. Max and min OTC for North of Hanford, Cross Cascades North & South, South of Snoking, West of Coyote, Raver-Paul, Keeler-Allston, Alturas, Idaho-NW, Brownlee East are based on no outage maximum and
9. Max and min OTC for Path C and Montana-SE are based on seasonal nomogram ranges.
10. For Path C & Montana-SE heavy load period is defined as 7AM-11PM MST. Light load period is defined as 11PM-7AM MST and all hours on Sunday and holidays.
11. Cross Cascades North & South are potential problems during extreme winter peak loads

Transmission Nomograms



*Sum of flows on Midway-Vincent, PDCI, IPP, North of Lugo, and WOR.

1999-2000 Winter --- Path C vs Bridger-Rock Springs

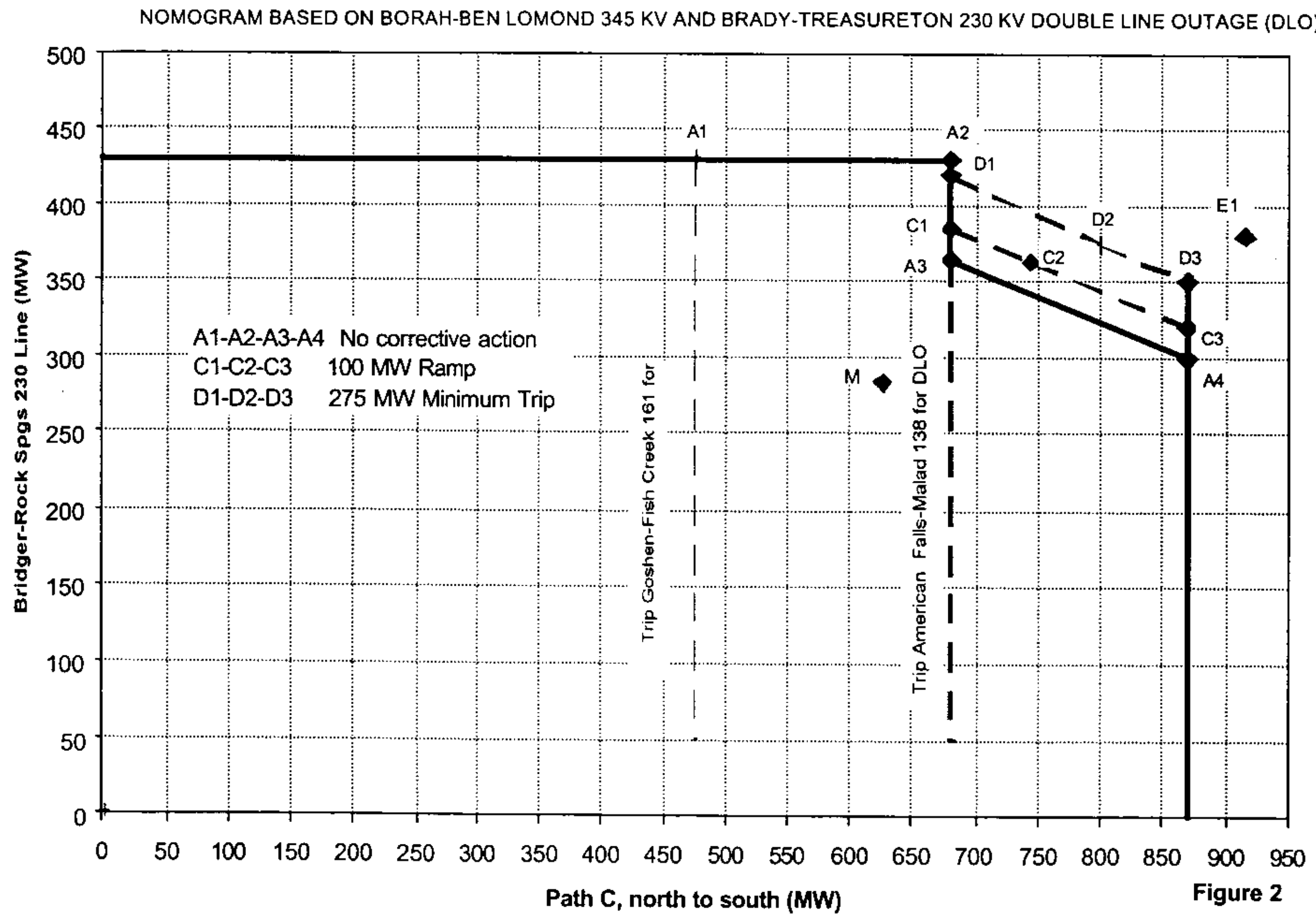


Figure 2

Transmission Nomograms, cont'd.

1999 Summer --- Path C vs Bridger-Rock Springs

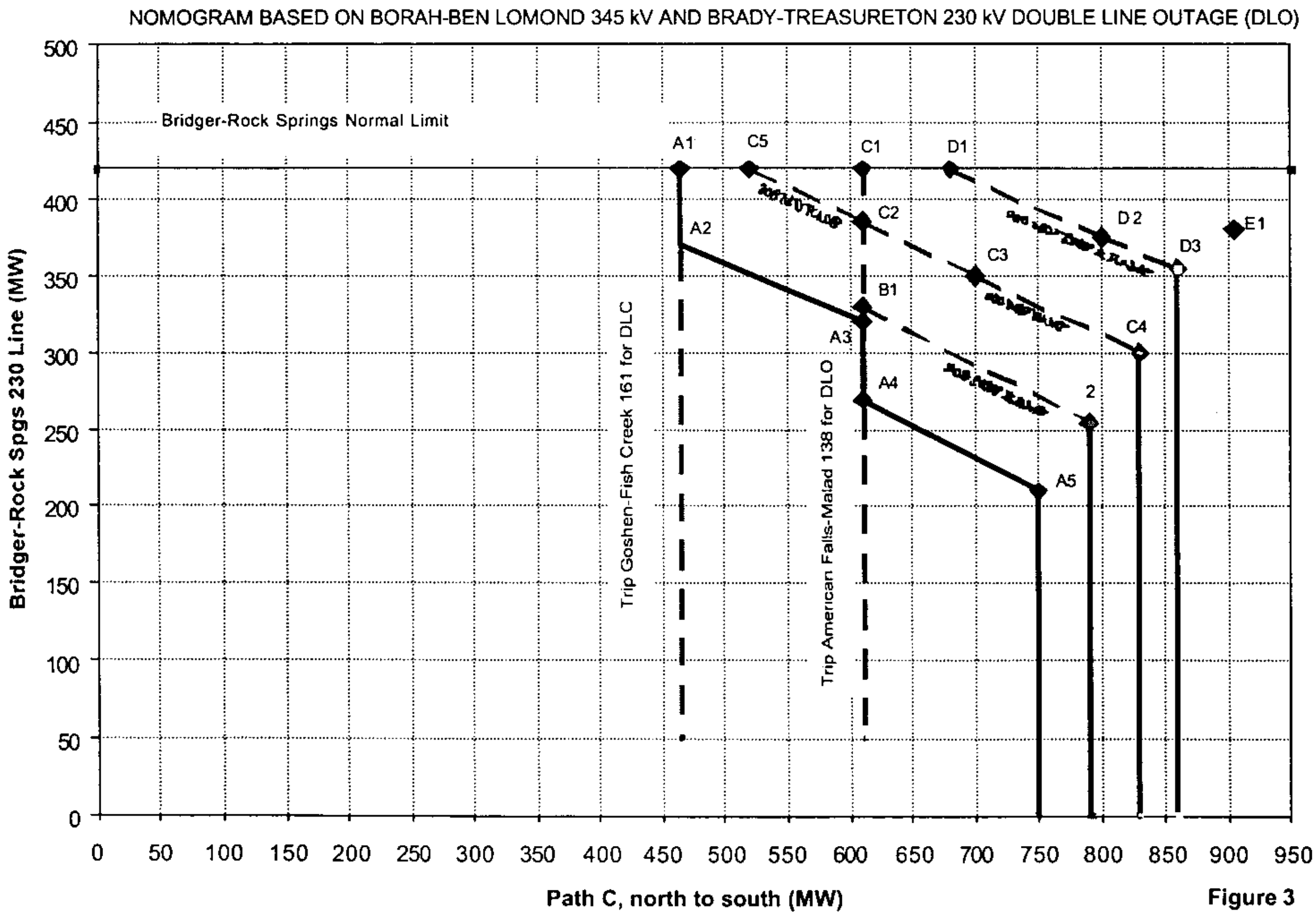
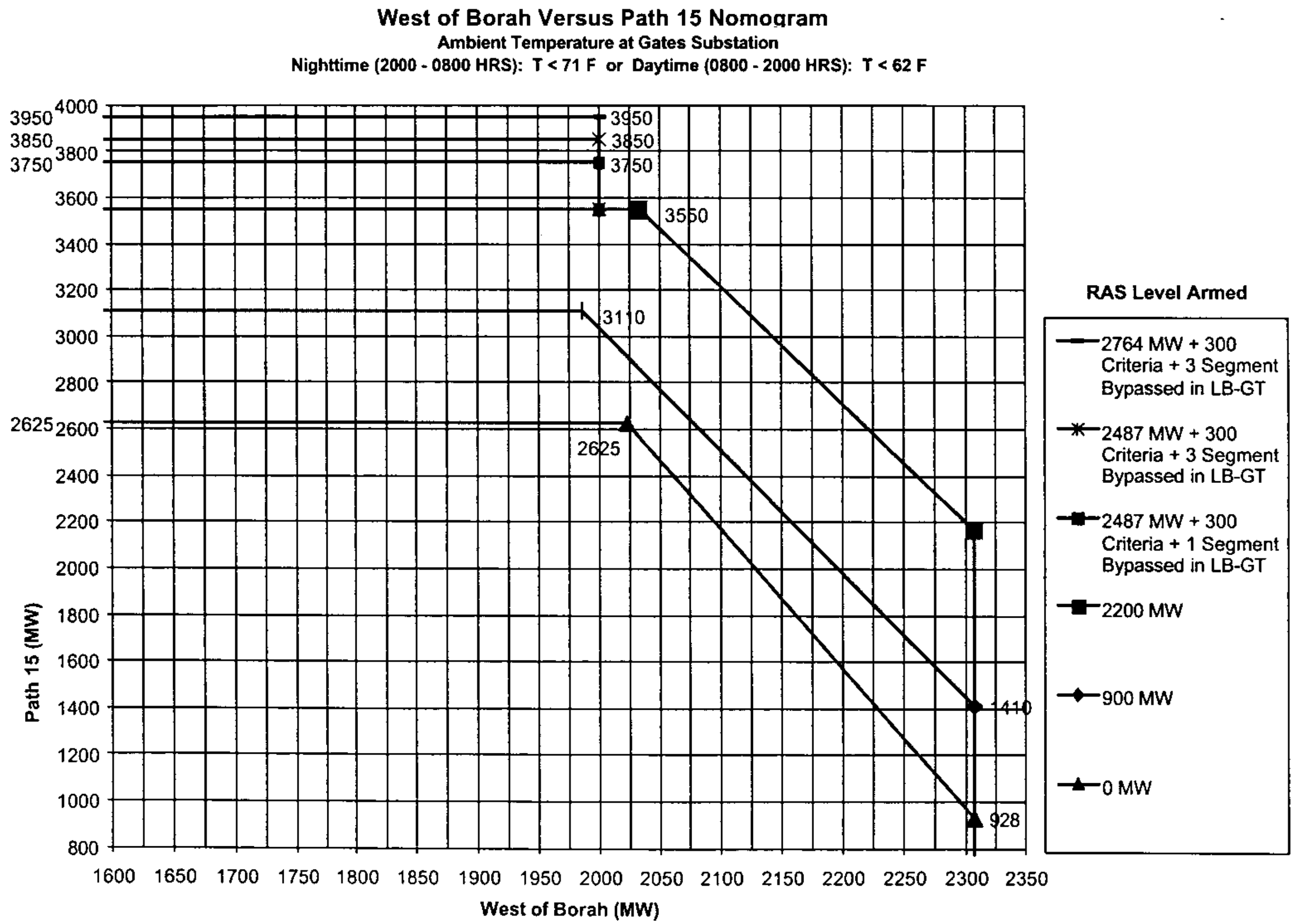


Figure 3

West of Borah Versus Path 15 Nomogram



Appendix 6

Monthly Hydro Generation by Load Area (GWh)

Region	Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Alberta	Alberta Power	140	119	110	141	119	164	215	124	101	112	155	143
CA ISO	LA Dept of Water & Power	42	23	63	63	35	28	52	50	65	30	23	11
CA ISO	Pacific Gas & Electric	1,925	2,166	2,696	2,768	2,991	2,862	2,692	2,388	1,813	1,512	1,324	1,661
CA ISO	Southern California Edison	297	296	471	511	574	534	537	455	377	261	195	296
Rocky Mtn	Public Service of Colorado	66	55	70	94	96	140	162	105	76	86	70	74
Rocky Mtn	WAPA Colorado-Missouri	186	166	200	231	356	393	388	328	236	173	182	203
RTO-West	Avista Corp	334	272	314	410	633	706	519	256	184	174	224	337
RTO-West	BC Hydro + W Kootenay	4,907	4,401	4,360	3,608	3,181	3,287	4,161	4,916	4,360	4,384	4,791	5,026
RTO-West	Bonneville Power Admin	8,085	6,940	7,040	7,481	8,552	7,670	6,647	6,552	5,778	4,267	5,529	6,671
RTO-West	Chelan Douglas Grant PUD	1,777	1,452	1,613	2,194	2,667	2,245	1,762	1,652	1,423	1,003	1,431	1,417
RTO-West	Idaho Power Company	756	787	846	882	1,124	796	905	825	751	525	433	552
RTO-West	Montana Power Company	321	258	256	266	328	322	331	317	229	237	270	289
RTO-West	Pacificorp West	378	319	306	346	322	333	269	237	218	208	322	484
RTO-West	Portland General Electric	264	225	251	233	214	168	151	142	142	159	217	249
RTO-West	Puget Sound Energy	125	118	102	93	138	132	117	88	71	118	127	120
RTO-West	Seattle City Light	770	675	749	893	1,107	1,182	984	611	548	483	609	840
W Connect	El Paso Electric	9	8	12	13	12	12	13	11	12	11	8	10
W Connect	Salt River Project	3	5	6	-	3	4	8	4	1	(5)	(4)	(1)
W Connect	WAPA Lower Colorado	626	623	753	819	816	845	878	866	683	582	560	671

Attachment 2: Fuel Price Assumptions

MEMORANDUM

TO: RTO West
FROM: Alex Rudkevich; TCA
CC: Assef Zobian, Ellen Wolfe; TCA
RE: Fuel Price Projections for the WSCC Region
DATE: September 21, 2002

Fuel categories

This memo deals with prices for natural gas, distillate (#2) and residual (#6) fuel oil.

Geographical markets

The forecast covers the entire Mountain and Pacific regions of the 48 states and Canadian provinces of Alberta and British Columbia.

Basis forecasts

The key underlying forecasts are projected prices for crude oil (WTI) and for natural gas (Henry Hub). All other forecasts are derived from these two basic forecasts using projected and/or historical basis differentials as explained later in this memo.

Figure 1 presents TCA's proposed base case forecast of crude oil prices in comparison with historical prices, NYMEX futures prices for the light sweet crude oil (as of September 21, 2001) and a long-term forecast for crude oil prices from EIA's Annual Energy Outlook–2001. As one can see, our proposed forecast is a composition of futures prices in the short term (2001–2003) and EIA's forecast in the long term (2004–2020). It is important to note that the futures prices and the EIA forecast for 2004 are very close.

Similarly, Figure 2 presents TCA's proposed forecast for the spot price of natural gas at Henry Hub. The forecast is shown in comparison with average NYMEX futures prices (as of September 21, 2001) and a long-term forecast per EIA's Annual Energy Outlook–2000.[70] Our proposed forecast is a composition of futures prices in the short term (2001–2003), EIA's long-term forecast in the long term (2005–2020) and a midpoint for these two projections for 2004. Although the resulting forecast for 2004 appears slightly higher than the EIA forecast, the numbers are relatively close. In other words, by that period we observe the convergence between the market outlook (futures prices) and the long-term outlook developed by the EIA.

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[70] AEO-2001 does not forecast Henry Hub prices, instead it predicts prices at the wellhead. To come up with the Henry Hub price forecast, we use a historical basis differential of $0.17/Mmbtu.

Figure 1. Crude Oil Prices: History and Projections (2000$/BBL)

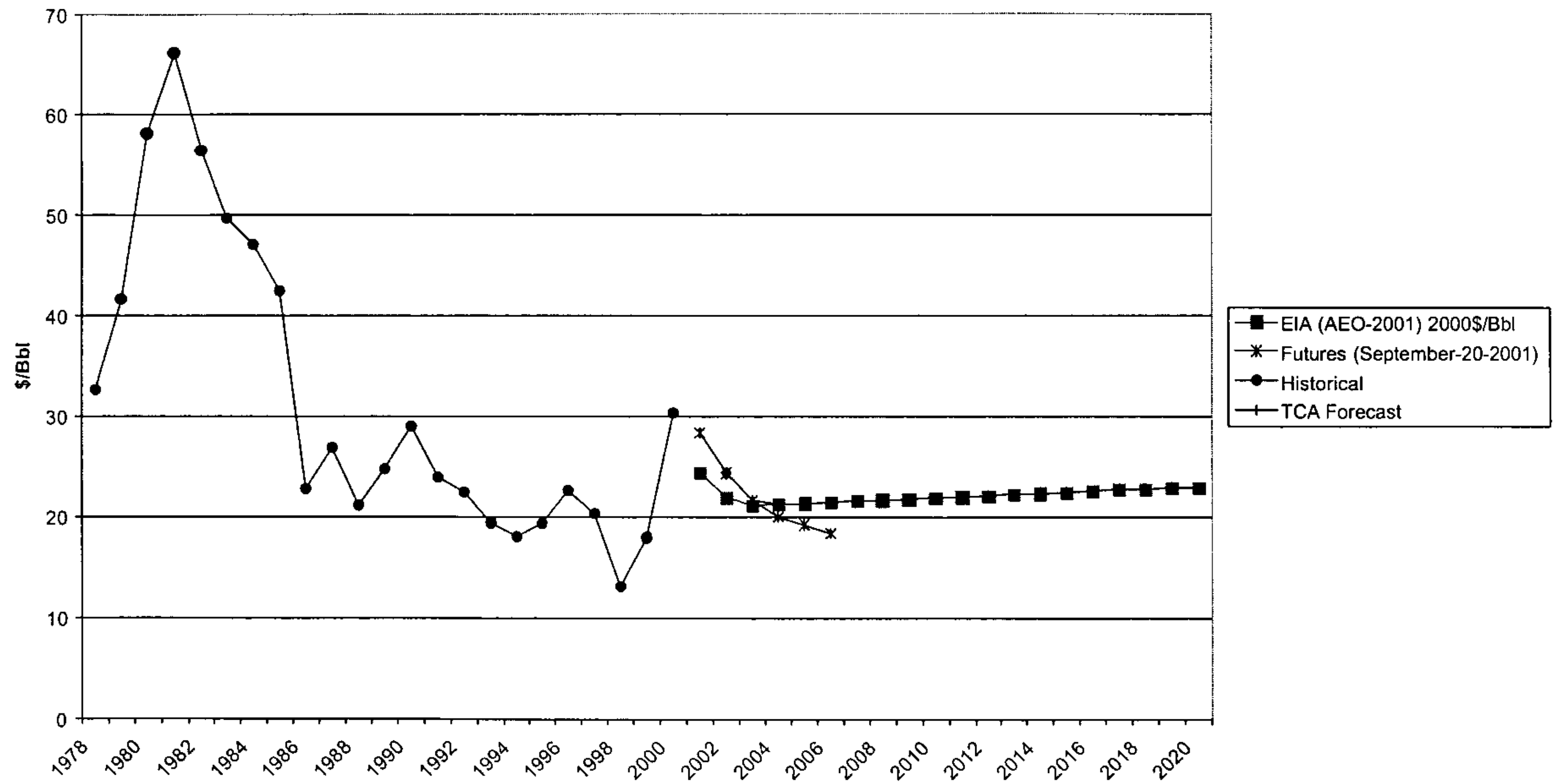
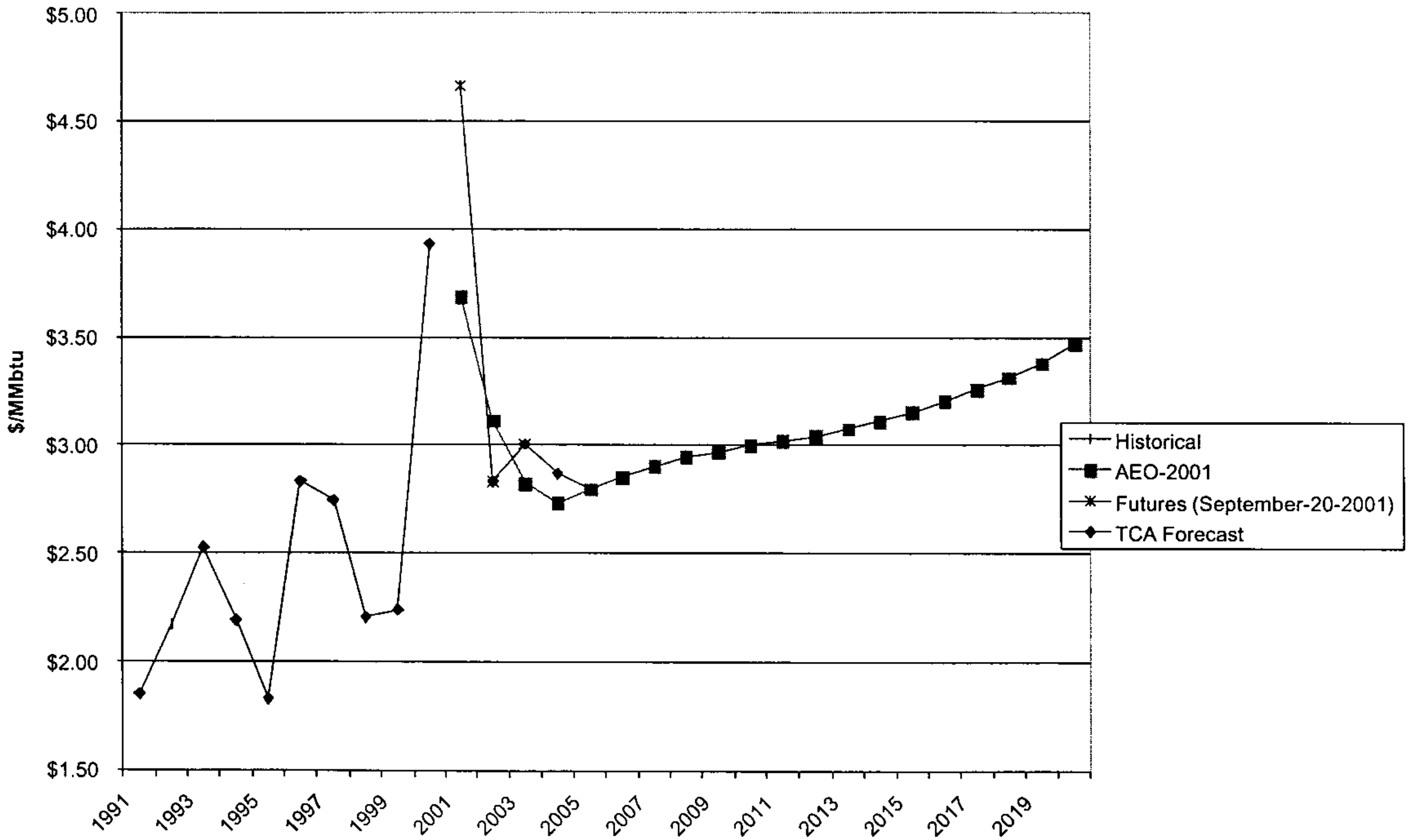


Figure 2. Natural Gas Spot Prices at Henry Hub: History and Projections (2000$/MMbtu)



Generation Fuel Prices

Generation fuel prices are derived from basis forecasts.

Fuel oil prices—methodology

To derive fuel oil prices for electric generation, we use an in-house linear regression model linking crude oil prices with # 6 and # 2 fuel oil in the Northeastern U.S. (New York Harbor). For petroleum prices in other regions, we use state-specific basis differentials using EIA Form 423 data for 1997–2000 and historical spot prices for # 2 and # 6 fuel oil at New York Harbor. We assume a modest seasonal pattern for # 2 fuel oil prices, the same in all regions. Prices for #6 fuel oil are assumed flat.

Natural gas prices – methodology

We develop natural gas projections for the following regions:

- Northern California
- Southern California
- Northern Nevada
- Southern Nevada
- Colorado
- Oregon–Washington
- Utah
- New Mexico–Arizona–Texas (El Paso only)
- Idaho–Montana–Wyoming
- British Columbia
- Alberta

The burner-tip price for natural gas is a sum of two components—regional price and local delivery price.

Local delivery price is differentiated by the electric utility control area. This differentiation is applied *to existing plants only*[71]. Thus estimated deliverability burner-tip component for existing plants is assumed to be effective for year 2000 only. For outer years we let this adder slide linearly to the level of $0.20/MMBtu by the year 2011. However, if this adder is less than $0.20/MMBtu, it remains flat at that level for the entire

[71] TCA conducted an extensive analysis of actual burner-tip costs for the historical period 1998-2000. We analyzed fuel costs on a plant-by-plant basis vis-à-vis regional historical spot prices of natural gas. This plant-by-plant analysis yields unstable results. We believe that this is because generation owners make their fuel purchasing decisions not on a unit-by-unit basis but rather on a system basis. As a results, fuel costs reported by plant often reflect accounting decisions rather than actual economics of fuel supply. In order to smooth this effect, it is more reasonable to conduct this analysis on a company basis. For modeling convenience given the current structure of information in TCA GE MAPS database, we used the notion of control area as a proxy for the generation operator.

forecast period. This linear decline reflects our assumption that generating companies would renegotiate their contract with natural gas suppliers such that prices should be closer to spot prices than they currently appear. The remaining $0.20/MMBtu adder should reflect unavoidable LDC and/or lateral charge. (This is our "best-guess estimate.") For new gas-fired plants, the local component is set at $0.07/MMBtu to reflect pipeline lateral charges. (This is our "best-guess" estimate.)

Following is a table of estimated deliverability charges for existing plants by state and control area. The additional charge is from the nearest Hub.

State/Control area	Charge ($/MMBtu)		State/Control area	Charge ($/MMBtu)	
	2000	2004		2000	2004
AZ AEPCO	0.35	0.29	CO CSW	0.67	0.50
AZ APS	0.59	0.45	CO PSCo	0.85	0.62
AZ IID	0.56	0.43	CO NUGs	0.66	0.49
AZ SRP	0.74	0.54	CO Other	0.34	0.29
AZ TEP	0.96	0.68			
AZ Other	0.55	0.43	ID WWPC	0.56	0.43
CA CAMXNGCO	0.41	0.33	NM EPE	0.11	0.11
CA LDWP	0.86	0.62	NM PNM	0.45	0.36
CA NCMID	0.42	0.34	NM Other	0.24	0.23
CA PG&E	0.52	0.40			
CA SCE	0.62	0.47	NV NEVP	0.56	0.43
CA IID	0.70	0.39	NV SPP	0.11	0.11
CA SMUD	0.21	0.21	NV Other	0.34	0.29
CA SDGE	0.51	0.39			
CA Other	0.54	0.30	OR PGE	0.14	0.14
			OR Other	0.11	0.11
TX EPE	0.45	0.36			
			WA PSPL	0.45	0.36
UT PAC	0.53	0.41	WA WWPC	0.45	0.36
UT Other	0.35	0.29	WA NUGs	0.45	0.36
			WA Other	0.45	0.36
WY	0.40	0.33			

Forecast regional gas prices are derived from the Henry Hub forecast using TCA in-house regression models calibrated on historical regional prices vs. prices at Henry Hub. The relevant price point by region are identified below:

No.	Region	Henry Hub Prices Regressed to:
1	Northern CA	PG&E Citygates (Jan 98 through Apr 2001)
2	Southern CA	Southern CA Border (Jan 98 through Apr 2001)
3	Southern Nevada	Kern River (Jan 98 through Apr 2001)
4	Northern Nevada	Average of NPL Prices for Domestic and Stanfield points (Jan 98 through Apr 2001)
4	Colorado	Average of CIG (N.Syst) and DJ Basin prices (Jan 98 through Apr 2001)
5	Oregon–Washington	Average of PGT (Kingsgate) and Northwest Stanfield prices (Jan 98 through Apr 2001)
6	Utah	Average of Kern River and Questar prices (Jan 98 through Apr 2001)
7	New Mexico–Arizona–Texas (El Paso)	San Juan Basin prices (Jan 98 through Apr 2001)
8	Idaho–Montana–Wyoming	CIG (N.Syst) prices (Jan 98 through Apr 2001)
9	British Columbia	PGT Kingsgate prices (Jan 98 through Apr 2001)
10	Alberta	NOVA (AECO-C) prices (Jan 98 through Apr 2001)

Seasonal patterns are developed in the following manner.

- For Henry Hub, we estimate historical seasonal pattern based on 1998–2000 actual monthly prices.
- Regional seasonal patterns appear automatically by applying the regression model to the monthly Henry Hub forecast.

Figures 3–12 present comparisons of monthly generation fuel prices for the period 2001–2010. Figures 13A and 13B provide a comparison of regional natural gas prices. Please note that on these figures we show burner-tip natural gas prices applicable for the new generating projects (with local component equal to \$0.07/MMBtu).

Figure 3. Fuel Price Forecast: N. California

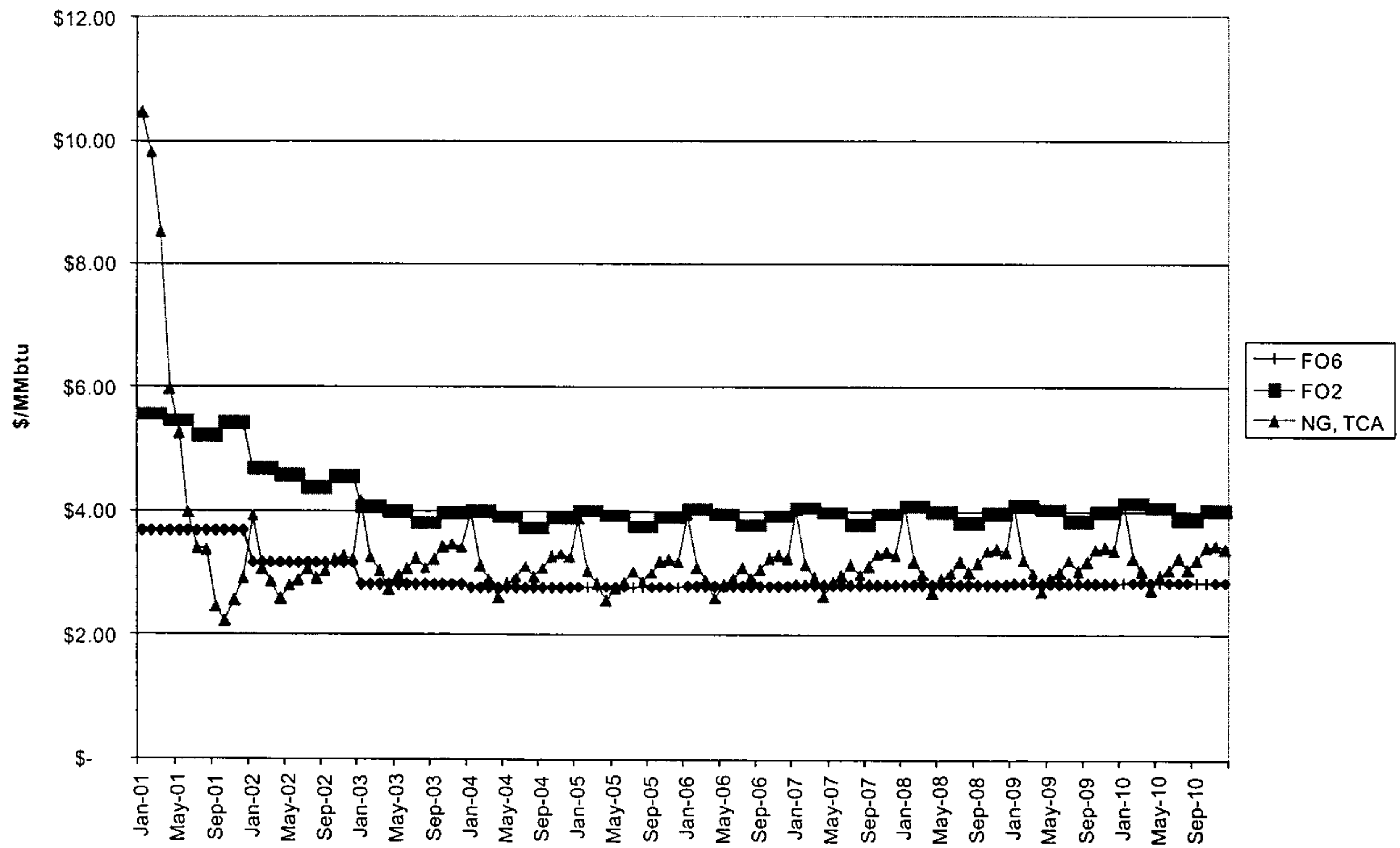


Figure 4. Fuel Price Forecast: S. California

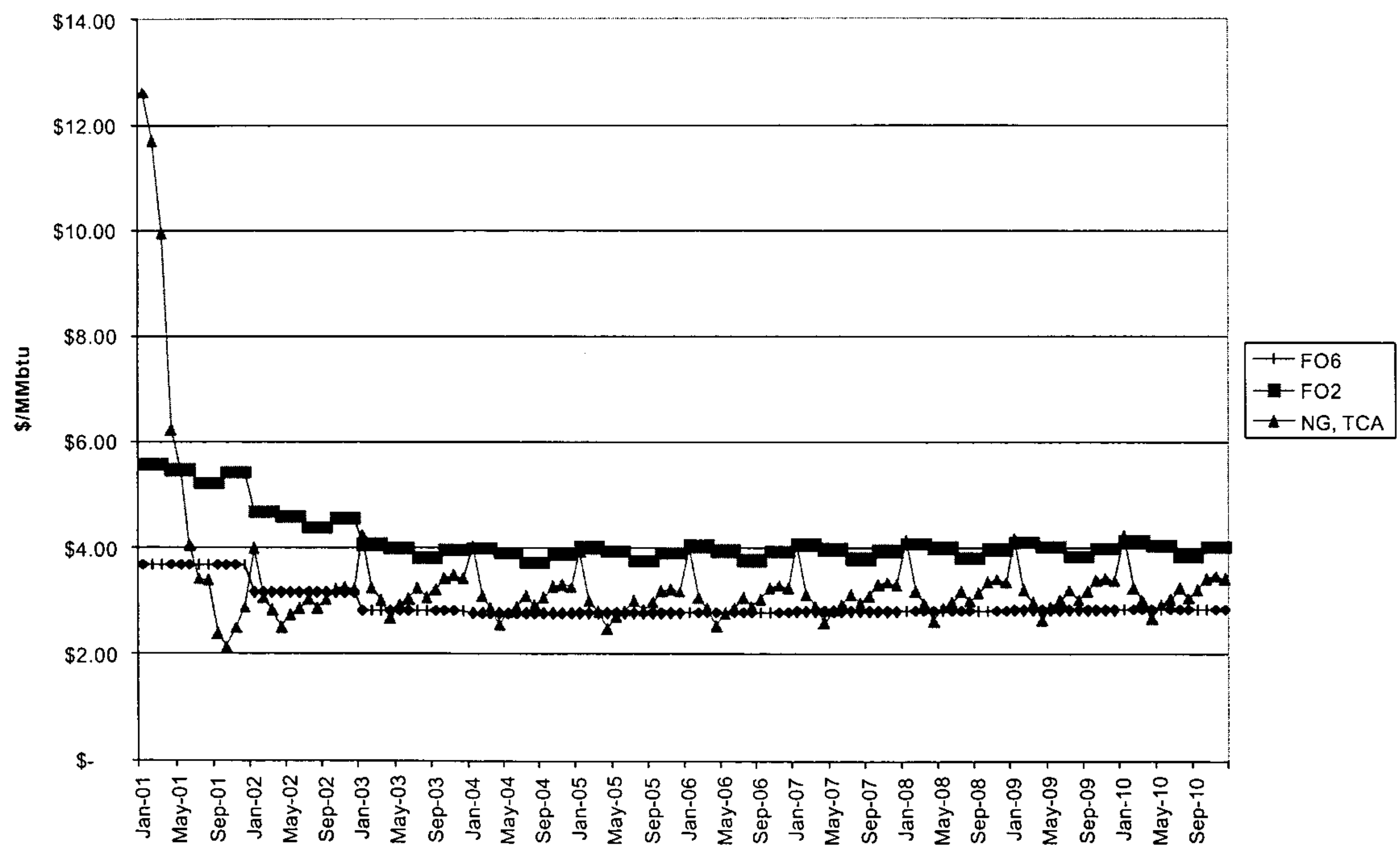


Figure 5. Fuel Price Forecast: Nevada

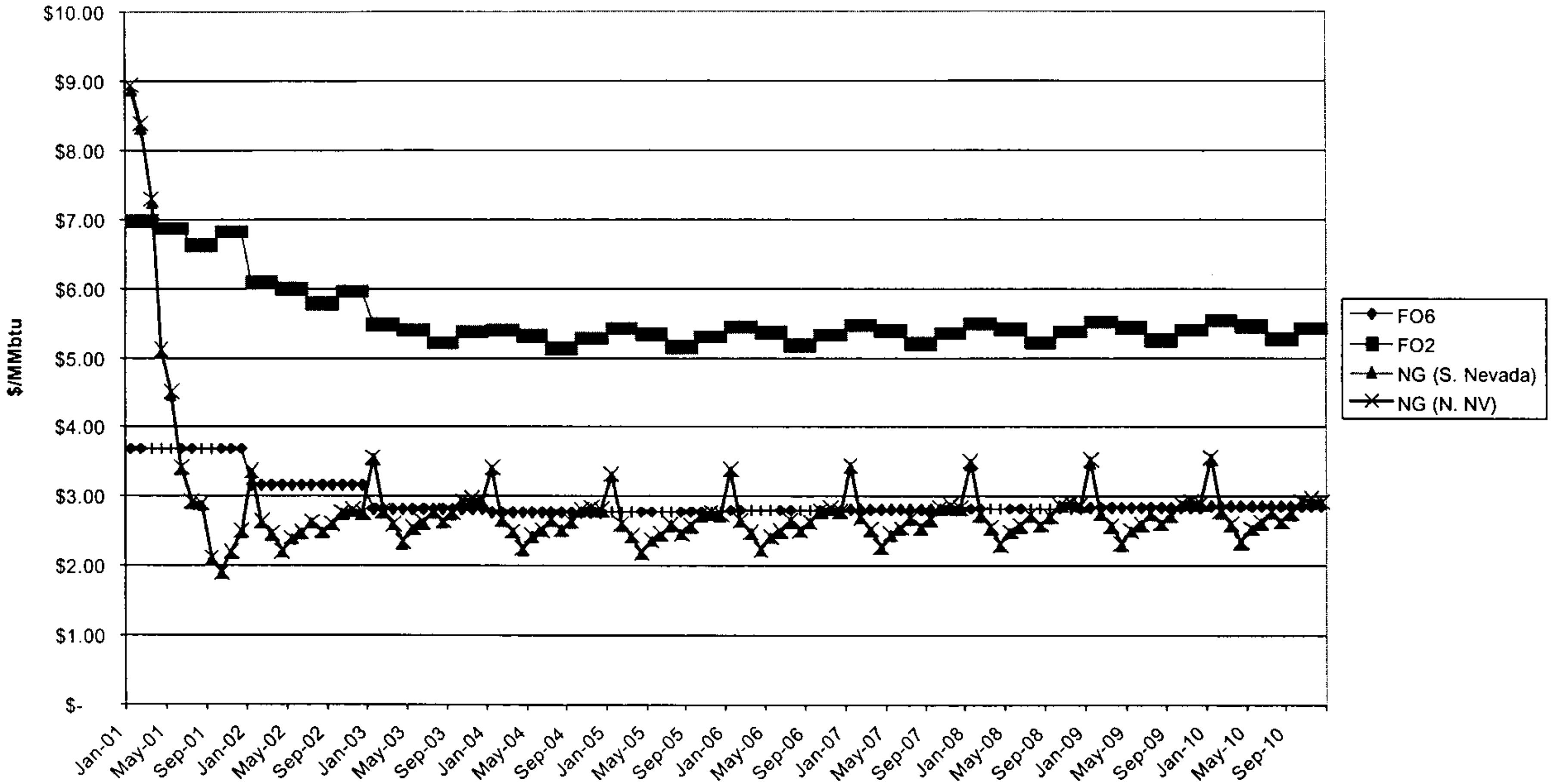


Figure 6. Fuel Price Forecast: Colorado

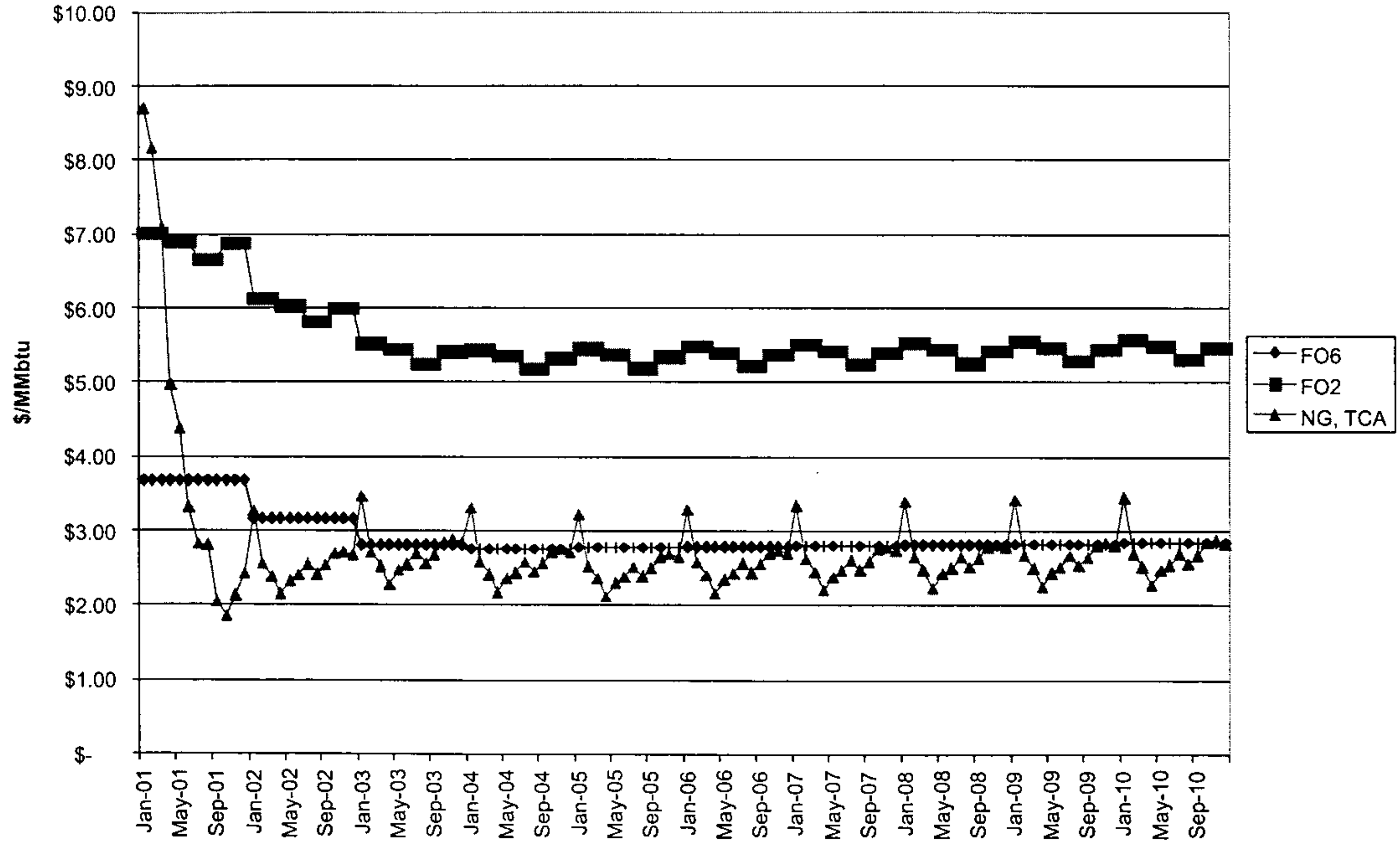


Figure 7. Fuel Price Forecast: Oregon-Washington

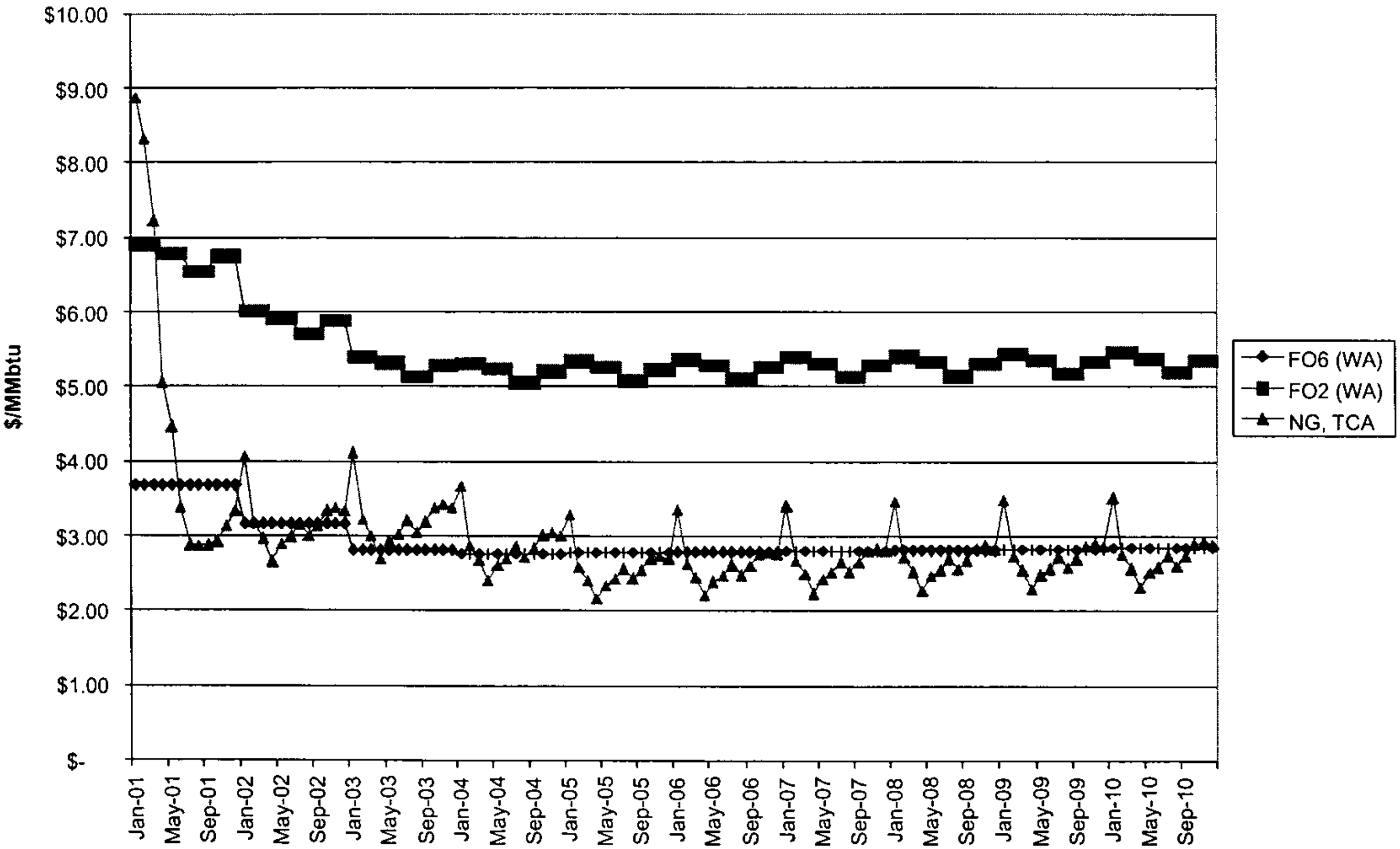


Figure 8. Fuel Price Forecast: Utah

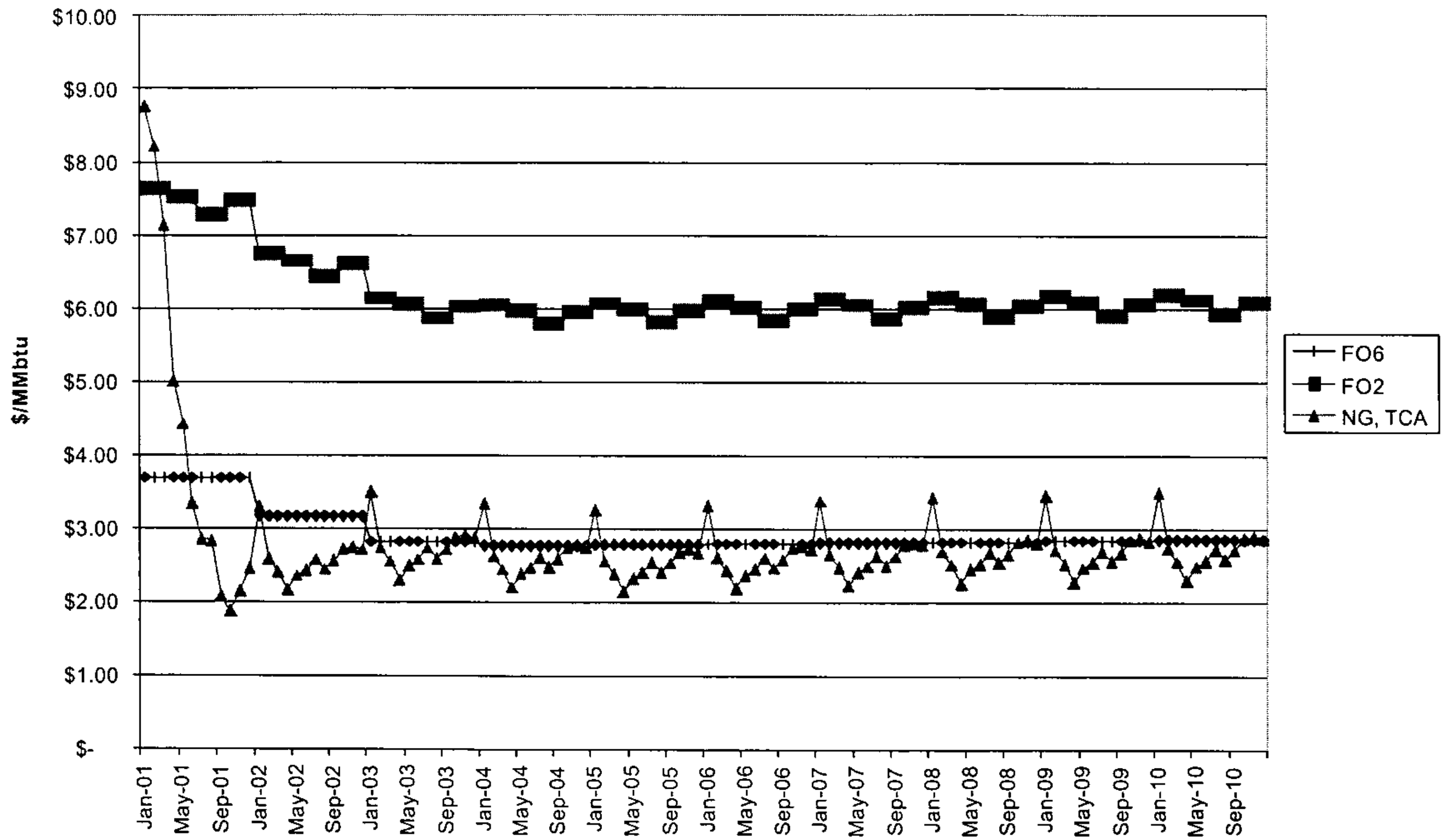


Figure 9. Fuel Price Forecast: New Mexico-Arizona

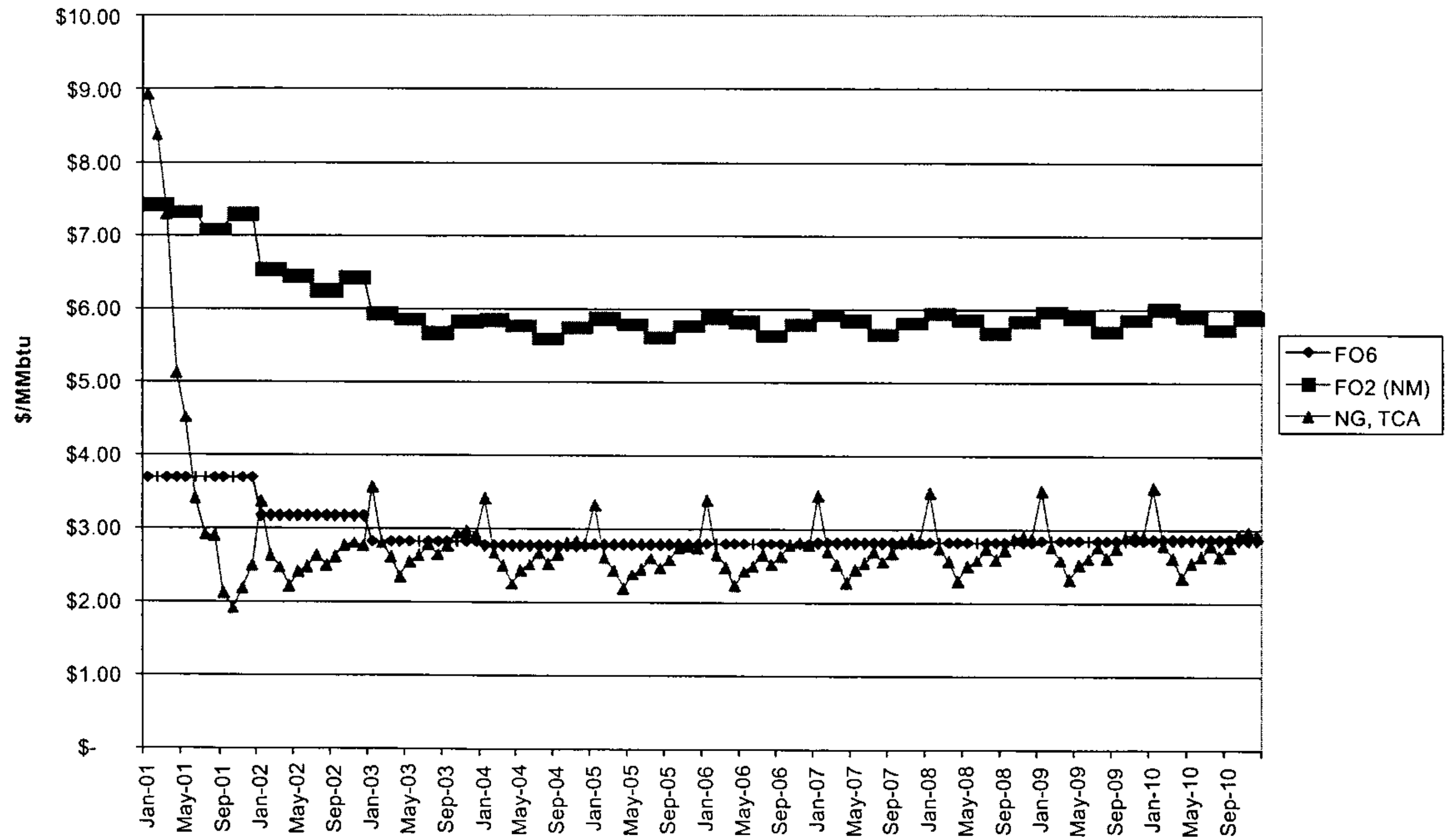


Figure 10. Fuel Price Forecast: Idaho-Montana-Wyoming

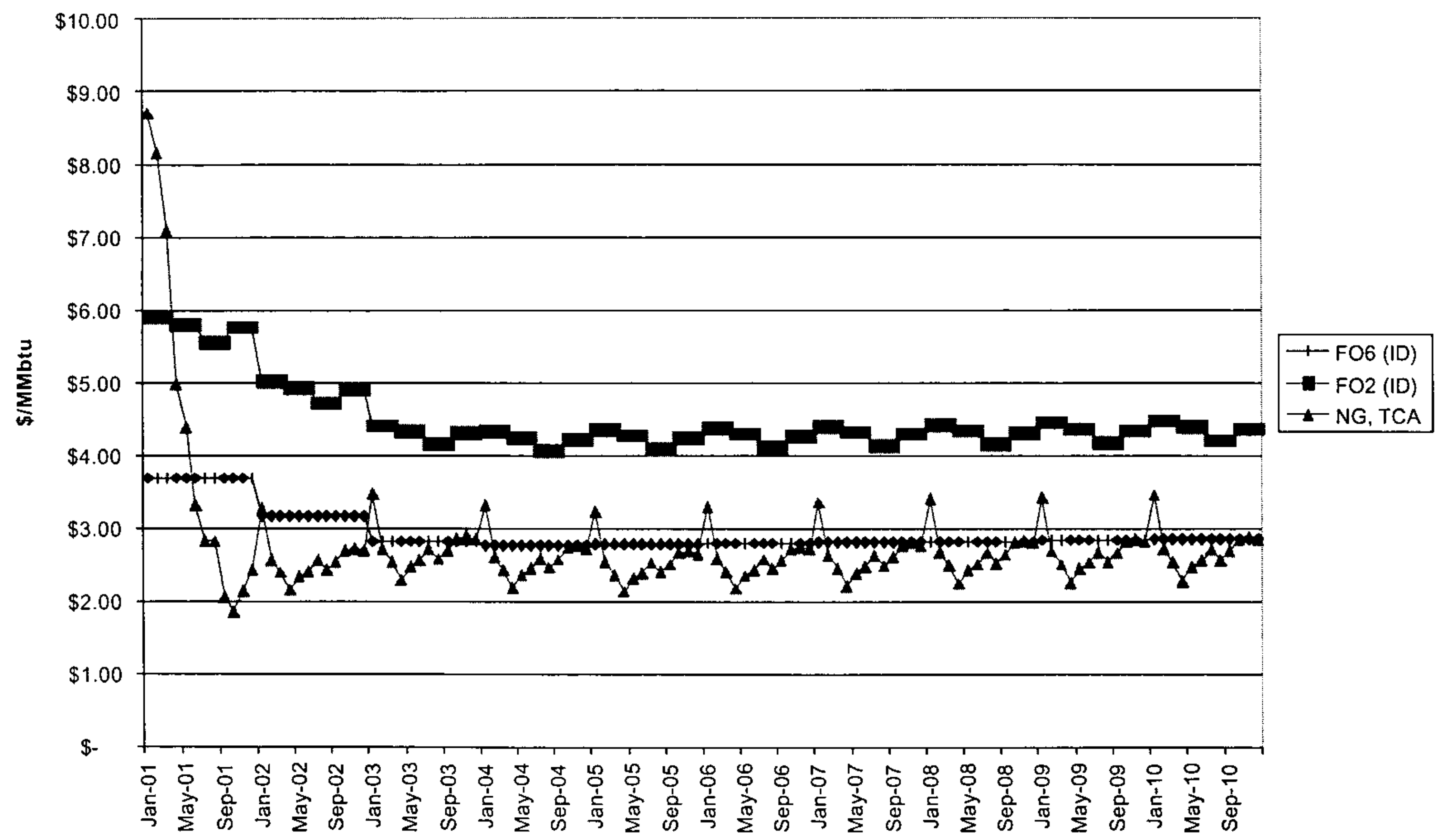


Figure 11. Fuel Price Forecast: British Columbia

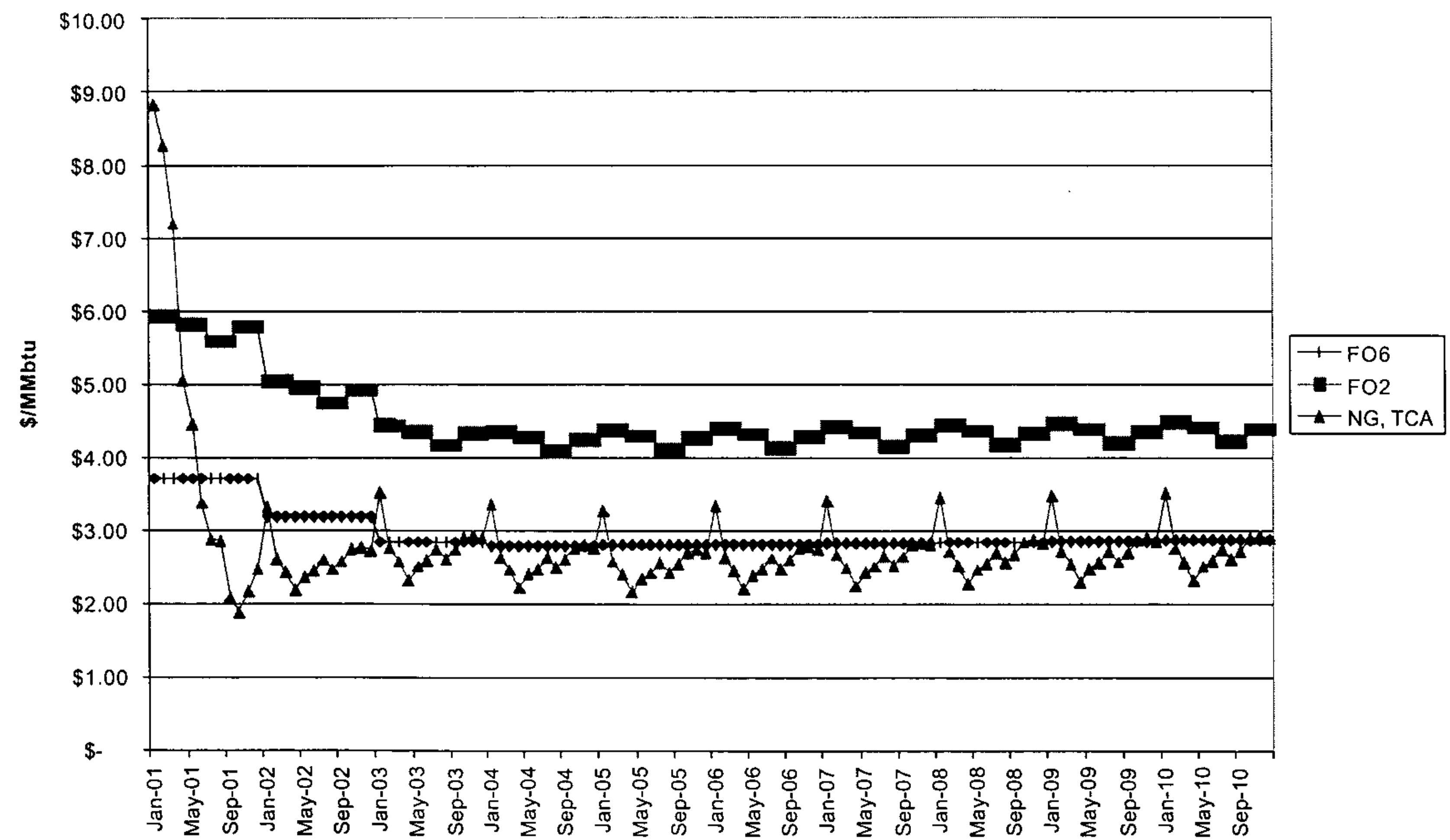


Figure 12. Fuel Price Forecast: Alberta

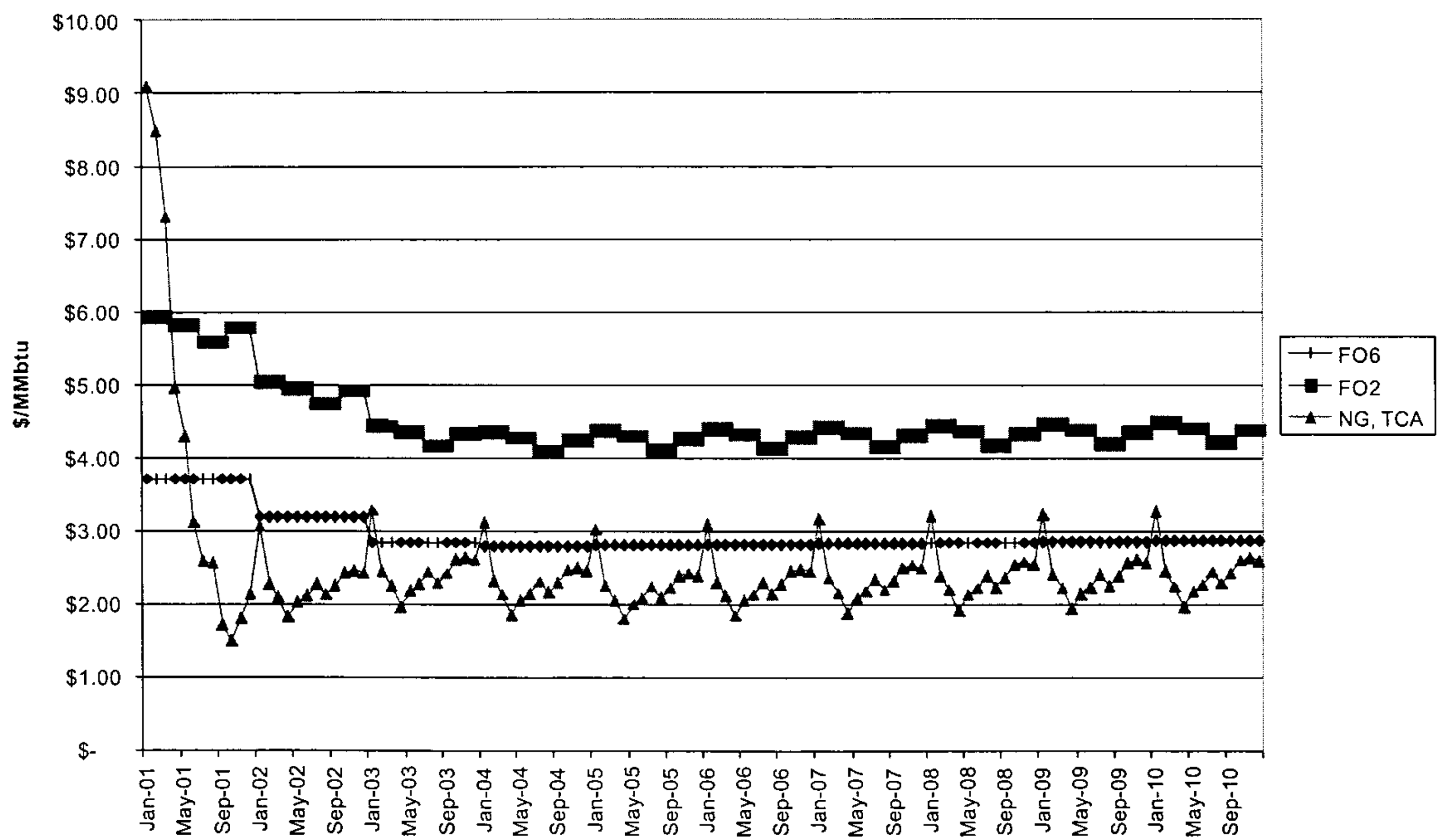


Figure 13A. Comparison of Regional Monthly Natural Gas Prices (2001-2010)

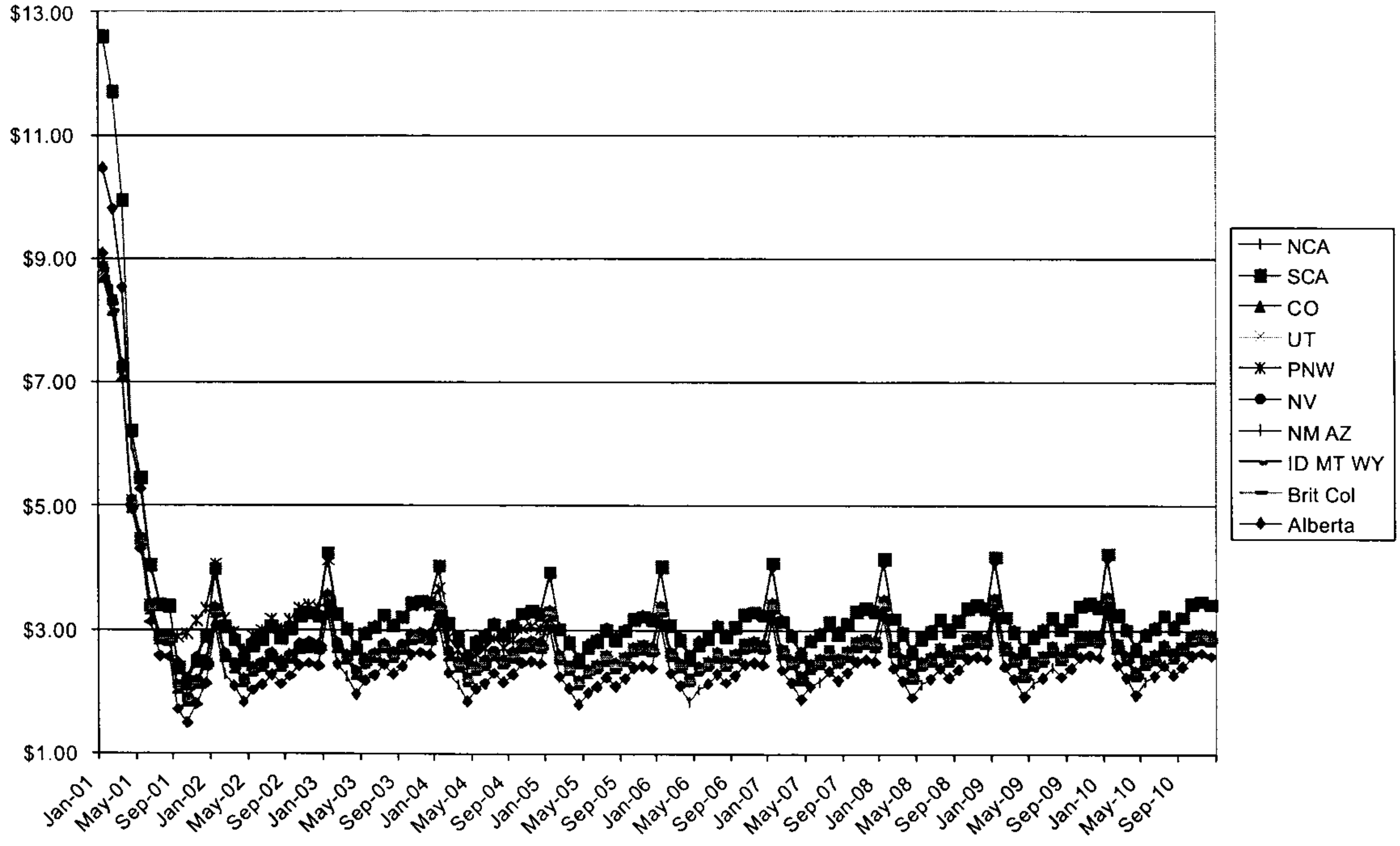
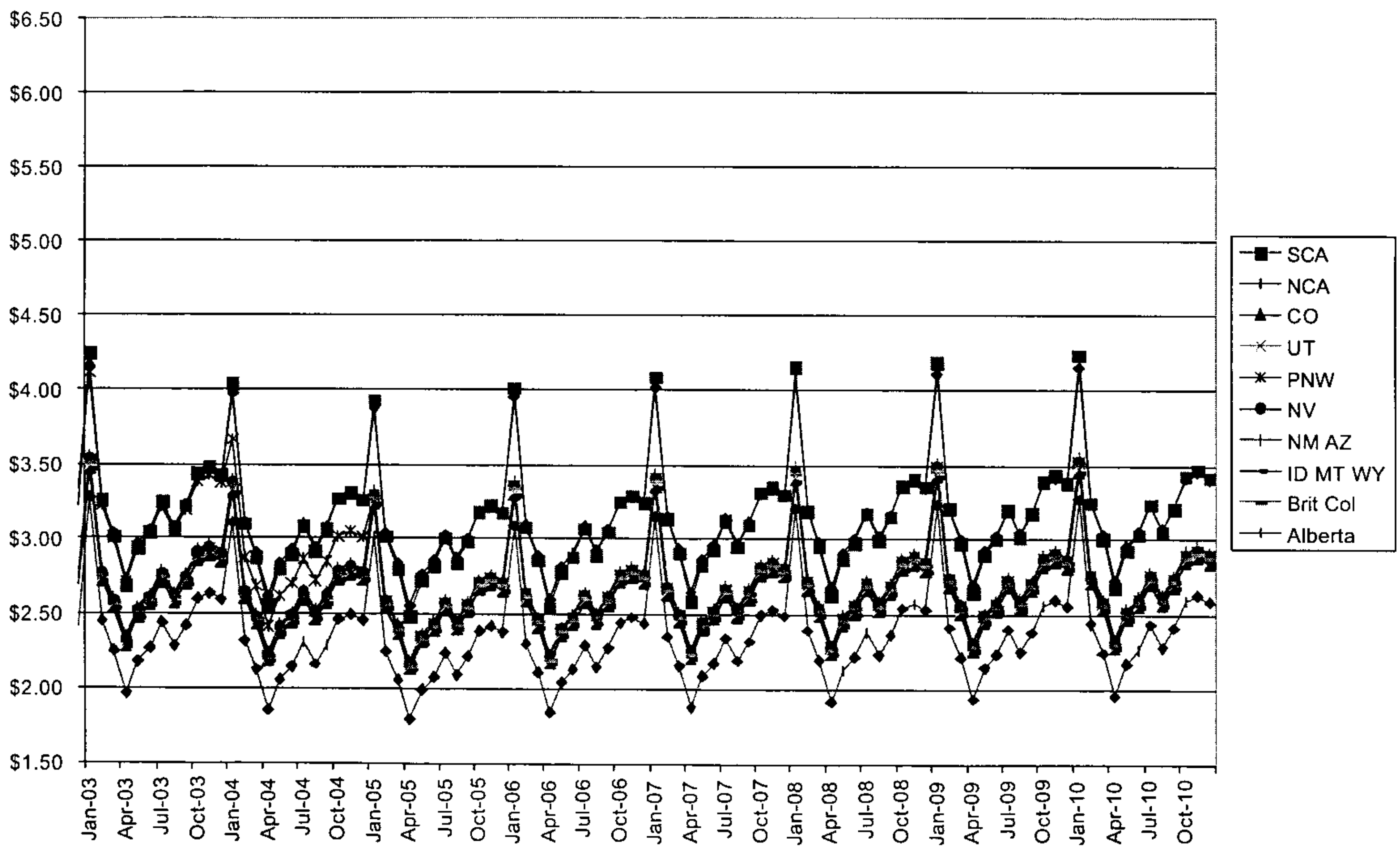


Figure 13B. Comparison of Regional Monthly Natural Gas Prices (2003-2010)



Attachment 3: Sensitivity Results: Annual Average Locational Energy Price Tables

Table 30: Annual Average Energy Price (Real 2000$/MWh) : Short Supply Case (Low Water/High Gas Price)

Annual Average Energy Price (Real 2000$/MWh)				
Area	Region	Without RTO	With RTO	% Change
BC Hydro + W Kooteny	RTO-West	42.53	41.55	(2.31)
Avista Corp	RTO-West	40.21	35.81	(10.94)
Bonneville Power Admin	RTO-West	39.60	35.71	(9.83)
Chelan Douglas Grant PUD	RTO-West	39.08	35.67	(8.73)
Idaho Power Company	RTO-West	34.98	34.38	(1.73)
Montana Power Company	RTO-West	34.10	32.73	(4.03)
Nevada Power Company	RTO-West	36.99	34.57	(6.55)
Pacificorp East	RTO-West	34.91	31.98	(8.37)
Pacificorp West	RTO-West	36.82	35.55	(3.43)
Portland General Electric	RTO-West	37.20	35.64	(4.20)
Puget Sound Energy	RTO-West	40.36	35.68	(11.60)
Seattle City Light	RTO-West	39.61	35.66	(9.97)
Sierra Pacific Power	RTO-West	44.58	39.45	(11.50)
Tacoma Public Utilities	RTO-West	39.19	35.67	(8.98)
Alberta Power	ALBERTA	27.53	26.70	(3.02)
LA Dept of Water & Power	CA ISO	38.59	35.08	(9.09)
Pacific Gas & Electric	CA ISO	38.71	35.43	(8.48)
San Diego Gas & Electric	CA ISO	37.79	34.89	(7.67)
Southern California Edison	CA ISO	38.50	35.27	(8.39)
Public Service of Colora	Rocky Mtn	40.06	30.03	(25.05)
WAPA Colorado-Missouri	Rocky Mtn	34.25	30.08	(12.18)
WAPA Upper Missouri	Rocky Mtn	38.69	30.01	(22.43)
Arizona Public Service	WConnect	36.76	31.77	(13.57)
El Paso Electric	WConnect	41.27	34.20	(17.11)
Imperial Irrigation Dist	WConnect	36.22	32.52	(10.23)
Public Service New Mexico	WConnect	37.08	31.66	(14.60)
Salt River Project	WConnect	36.70	31.68	(13.69)
Tucson Electric Power	WConnect	36.44	31.40	(13.83)
WAPA Lower Colorado	WConnect	36.76	31.47	(14.39)

Table 31: Annual Average Energy Price (Real 2000$/MWh): Transmission Line Losses Fixed as in Without RTO

Annual Average Energy Price (Real 2000$/MWh)				
Area	Region	Without RTO	With RTO	% Change
BC Hydro + W Kooteny	RTO-West	35.80	34.67	(3.15)
Avista Corp	RTO-West	35.50	31.14	(12.29)
Bonneville Power Admin	RTO-West	34.82	30.30	(12.98)
Chelan Douglas Grant PUD	RTO-West	34.18	29.88	(12.56)
Idaho Power Company	RTO-West	30.30	28.38	(6.36)
Montana Power Company	RTO-West	25.24	25.07	(0.69)
Nevada Power Company	RTO-West	33.75	29.88	(11.48)
Pacificorp East	RTO-West	30.16	26.59	(11.85)
Pacificorp West	RTO-West	32.73	28.91	(11.68)
Portland General Electric	RTO-West	33.42	29.47	(11.81)
Puget Sound Energy	RTO-West	35.60	31.25	(12.21)
Seattle City Light	RTO-West	34.82	30.47	(12.48)
Sierra Pacific Power	RTO-West	40.99	33.40	(18.52)
Tacoma Public Utilities	RTO-West	34.42	30.07	(12.65)
Alberta Power	ALBERTA	23.98	23.14	(3.49)
LA Dept of Water & Power	CA ISO	34.39	30.72	(10.67)
Pacific Gas & Electric	CA ISO	32.88	31.05	(5.58)
San Diego Gas & Electric	CA ISO	32.20	30.68	(4.74)
Southern California Edison	CA ISO	32.93	31.15	(5.41)
Public Service of Colora	Rocky Mtn	32.66	26.75	(18.11)
WAPA Colorado-Missouri	Rocky Mtn	26.75	24.79	(7.34)
WAPA Upper Missouri	Rocky Mtn	27.59	24.53	(11.09)
Arizona Public Service	WConnect	31.17	28.35	(9.05)
El Paso Electric	WConnect	36.17	31.31	(13.44)
Imperial Irrigation Dist	WConnect	30.69	28.06	(8.58)
Public Service New Mexico	WConnect	33.16	28.53	(13.94)
Salt River Project	WConnect	31.12	28.27	(9.18)
Tucson Electric Power	WConnect	31.14	27.99	(10.10)
WAPA Lower Colorado	WConnect	31.11	27.94	(10.19)

Table 32: Annual Average Energy Price (Real 2000$/MWh): Scheduling Limits Fixed as in Without RTO

Annual Average Energy Price (Real 2000$/MWh)				
Area	Region	Without RTO	With RTO	% Change
BC Hydro + W Kooteny	RTO-West	35.80	34.41	(3.89)
Avista Corp	RTO-West	35.50	29.70	(16.34)
Bonneville Power Admin	RTO-West	34.82	29.75	(14.57)
Chelan Douglas Grant PUD	RTO-West	34.18	29.73	(13.01)
Idaho Power Company	RTO-West	30.30	28.93	(4.53)
Montana Power Company	RTO-West	25.24	26.82	6.27
Nevada Power Company	RTO-West	33.75	30.38	(9.99)
Pacificorp East	RTO-West	30.16	27.46	(8.94)
Pacificorp West	RTO-West	32.73	29.68	(9.33)
Portland General Electric	RTO-West	33.42	29.73	(11.05)
Puget Sound Energy	RTO-West	35.60	29.77	(16.39)
Seattle City Light	RTO-West	34.82	29.75	(14.56)
Sierra Pacific Power	RTO-West	40.99	33.21	(18.97)
Tacoma Public Utilities	RTO-West	34.42	29.75	(13.56)
Alberta Power	ALBERTA	23.98	23.81	(0.69)
LA Dept of Water & Power	CA ISO	34.39	30.99	(9.87)
Pacific Gas & Electric	CA ISO	32.88	31.32	(4.76)
San Diego Gas & Electric	CA ISO	32.20	30.97	(3.83)
Southern California Edison	CA ISO	32.93	31.41	(4.61)
Public Service of Colora	Rocky Mtn	32.66	25.72	(21.23)
WAPA Colorado-Missouri	Rocky Mtn	26.75	25.76	(3.73)
WAPA Upper Missouri	Rocky Mtn	27.59	24.56	(10.99)
Arizona Public Service	WConnect	31.17	27.77	(10.93)
El Paso Electric	WConnect	36.17	30.63	(15.32)
Imperial Irrigation Dist	WConnect	30.69	28.71	(6.44)
Public Service New Mexico	WConnect	33.16	27.80	(16.14)
Salt River Project	WConnect	31.12	27.68	(11.06)
Tucson Electric Power	WConnect	31.14	27.41	(11.96)
WAPA Lower Colorado	WConnect	31.11	27.42	(11.85)

Table 33: Annual Average Energy Price (Real 2000$/MWh): Maintenance Schedule Fixed as in Without RTO

Annual Average Energy Price (Real 2000$/MWh)				
Area	Region	Without RTO	With RTO	% Change
BC Hydro + W Kooteny	RTO-West	35.80	34.58	(3.41)
Avista Corp	RTO-West	35.50	30.03	(15.41)
Bonneville Power Admin	RTO-West	34.82	30.06	(13.68)
Chelan Douglas Grant PUD	RTO-West	34.18	30.03	(12.14)
Idaho Power Company	RTO-West	30.30	28.99	(4.33)
Montana Power Company	RTO-West	25.24	27.32	8.23
Nevada Power Company	RTO-West	33.75	30.43	(9.85)
Pacificorp East	RTO-West	30.16	27.42	(9.07)
Pacificorp West	RTO-West	32.73	29.94	(8.53)
Portland General Electric	RTO-West	33.42	30.01	(10.20)
Puget Sound Energy	RTO-West	35.60	30.07	(15.52)
Seattle City Light	RTO-West	34.82	30.05	(13.68)
Sierra Pacific Power	RTO-West	40.99	33.89	(17.33)
Tacoma Public Utilities	RTO-West	34.42	30.06	(12.67)
Alberta Power	ALBERTA	23.98	23.09	(3.70)
LA Dept of Water & Power	CA ISO	34.39	31.04	(9.73)
Pacific Gas & Electric	CA ISO	32.88	31.38	(4.58)
San Diego Gas & Electric	CA ISO	32.20	31.02	(3.67)
Southern California Edison	CA ISO	32.93	31.45	(4.50)
Public Service of Colora	Rocky Mtn	32.66	25.88	(20.75)
WAPA Colorado-Missouri	Rocky Mtn	26.75	25.91	(3.14)
WAPA Upper Missouri	Rocky Mtn	27.59	25.04	(9.26)
Arizona Public Service	WConnect	31.17	27.86	(10.63)
El Paso Electric	WConnect	36.17	30.56	(15.50)
Imperial Irrigation Dist	WConnect	30.69	28.79	(6.20)
Public Service New Mexico	WConnect	33.16	27.80	(16.15)
Salt River Project	WConnect	31.12	27.77	(10.76)
Tucson Electric Power	WConnect	31.14	27.54	(11.56)
WAPA Lower Colorado	WConnect	31.11	27.55	(11.44)

Table 34: Annual Average Energy Price (Real 2000$/MWh): Operating Reserves (non AGC)

Annual Average Energy Price (Real 2000$/MWh)				
Area	Region	Without RTO	With RTO	% Change
BC Hydro + W Kooteny	RTO-West	32.45	32.47	0.05
Avista Corp	RTO-West	32.42	28.90	(10.86)
Bonneville Power Admin	RTO-West	31.77	28.95	(8.85)
Chelan Douglas Grant PUD	RTO-West	31.13	28.94	(7.03)
Idaho Power Company	RTO-West	26.80	28.13	4.96
Montana Power Company	RTO-West	21.78	26.01	19.44
Nevada Power Company	RTO-West	31.17	29.75	(4.57)
Pacificorp East	RTO-West	26.95	26.72	(0.86)
Pacificorp West	RTO-West	29.57	28.89	(2.31)
Portland General Electric	RTO-West	30.28	28.94	(4.43)
Puget Sound Energy	RTO-West	32.57	28.97	(11.04)
Seattle City Light	RTO-West	31.77	28.95	(8.88)
Sierra Pacific Power	RTO-West	36.14	32.31	(10.60)
Tacoma Public Utilities	RTO-West	31.38	28.96	(7.72)
Alberta Power	ALBERTA	20.53	20.37	(0.80)
LA Dept of Water & Power	CA ISO	31.85	30.53	(4.15)
Pacific Gas & Electric	CA ISO	30.73	30.84	0.36
San Diego Gas & Electric	CA ISO	30.08	30.52	1.44
Southern California Edison	CA ISO	30.84	30.95	0.36
Public Service of Colora	Rocky Mtn	28.95	25.23	(12.84)
WAPA Colorado-Missouri	Rocky Mtn	23.02	25.27	9.75
WAPA Upper Missouri	Rocky Mtn	24.18	24.04	(0.61)
Arizona Public Service	WConnect	28.97	27.33	(5.67)
El Paso Electric	WConnect	33.53	29.71	(11.40)
Imperial Irrigation Dist	WConnect	28.57	28.27	(1.07)
Public Service New Mexico	WConnect	30.32	27.20	(10.30)
Salt River Project	WConnect	28.92	27.24	(5.80)
Tucson Electric Power	WConnect	28.87	26.97	(6.56)
WAPA Lower Colorado	WConnect	28.65	26.98	(5.83)

Attachment 4: Exchange Questions

RTO West Benefit/Cost Benchmarking Questions

1. Please provide the name, email address and phone number of the contact person for this survey
2. When did your exchange organize and begin operation?
3. What product(s) is (are) traded via your exchange (i.e. Energy, Reserves, Transmission Rights, etc.)?
4. Do you operate only "primary" exchanges for the direct sale of products, or do you offer secondary market products?
5. What geographic areas or regions does your exchange cover?
6. For the regions noted above, does your exchange operate within or as a single control area? If not, how many control areas are encompassed by your exchange?
7. What is the volume of each product traded on your exchange?
8. What was the initial cost of establishing the exchange(s) operated by your company? (Please state the currency if not reported in $US.) Please provide a breakdown to the extent possible (e.g., software, staffing, real estate, etc.)
9. What is the annual operating cost to maintain the exchange(s)? (Please state the currency if not reported in $US.)
10. If multiple products are traded via your exchange, please separate to the extent possible any of the setup costs according to exchange products.
11. If multiple products are traded via your exchange, please separate to the extent possible any of the ongoing operating costs according to exchange products.
12. Please provide information on cost recovery by addressing the following:
    a. Are exchange charges to customers itemized according to exchange market product? Is there a one-time, annual fee, or infrastructure cost for participating in the exchange?
13. Please provide a brief description of how your exchange interacts with system controllers? Can you characterize/elaborate on the information flow between the exchange and the system controller, including the type of data exchanged, the frequency, and the standards, if any, guiding such an exchange of information?

Attachment 5: SC Survey

Scheduling Coordinator (SC) and Qualified Scheduling Entity (QSE) Benchmarking Survey

1. Please provide the name, email address and phone number of the contact person for this survey.

2. When did your business begin operation?

3. What is the best source of public information on your SC/QSE business (e.g., website), if any?

4. What electric markets does your SC/QSE business serve? Please list the number of customers you presently have in each market, listing generators and load-serving entities separately.

5. What is the annual volume of MWh managed by your business?

6. Please describe the services offered by your business.

7. What was the initial capital cost of establishing your business? Please provide a breakdown of capital costs by major category to the extent possible (e.g., hardware, software, staff recruitment, real estate, etc.)

8. What is the annual cost to operate the business? Please provide a breakdown of operating costs by major category to the extent possible (e.g., direct labor, benefits, office supplies).

9. Please describe your pricing structure (i.e. provide transaction fees or other fee structure), including actual rates, and contractual terms for each service. If rates are typically negotiated with customers, please provide a best estimate of an average rate and a short description of typical contractual terms.

10. Please list the number of full-time, part-time and contract employees in your SC/QSE business.

11. To what extent have initial costs or ongoing costs contributed to efficiency or business improvements that are desirable regardless of your SC/QSE business?

12. Do you view your business as profitable?

13. Would you be willing to be contacted should we have further questions? If so, please provide your contact information.

George C. Mastrodonato
(360) 754-6001
mastrodonatog@lanepowell.com

April 23, 2002

Eric Christensen
Associate General Counsel
Snohomish County PUD
2320 California Street
P.O. Box 1107
Everett, WA 98206-1107

RE: Tax Implications of RTO West

Dear Mr. Christensen:

This letter and the attached summary constitute a revised analysis of the Oregon and Washington tax implications of the formation and operation of RTO West. We have revised our estimates of the tax impacts of RTO West based upon the state-by-state book values of Bonneville Power Administration ("BPA") transmission assets recently received from BPA. The availability of these book values has allowed us to refine our estimates of the tax liabilities that would arise from RTO West. Our fundamental conclusion – that RTO West will have serious tax consequences for electric ratepayers in the Pacific Northwest – remains unchanged.

The formation of RTO West is likely to create significant new tax liability primarily from the transfer of control of the Bonneville Power Administration's ("BPA") transmission assets, which are currently under federal control and ownership, to a new entity, RTO West, that does not enjoy exemption from state and local taxation. Substantial new taxes are also likely to arise from other structures currently proposed by RTO West, including Scheduling Coordinators and the Paying Agent Agreement.

We have analyzed the impact of RTO West under Washington and Oregon tax statutes. We conclude that formation of RTO West is likely to create major tax liability under several Oregon and Washington tax statutes. The applicable tax and our estimate of the likely range of potential tax liability under each tax are listed below:

EXHIBIT
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TAX	ESTIMATED LIABILITY
Washington Public Utility Tax	$57.5 million per year
Washington Property Tax	$1.5 million per year
Washington Leasehold Excise Tax	$46.5 to $61.5 million per year
Washington Sales/Use Tax	$248 to $328 million one-time payment
Oregon Property Tax	$36 to $48 million per year

These estimates are of new taxes that are likely to arise from the formation of RTO West. These estimates are also, because of constraints of time and resources, incomplete. We have not analyzed what new taxes that might arise in other states where RTO West would operate. However, there may be significant tax consequences in some of those states as well, especially in Idaho and Montana, which, according to BPA figures, are host to more than half a billion dollars of BPA transmission plant investments.

There may also be significant tax effects under Canadian or British Columbia provincial law, but we have not attempted to analyze those effects here. Nor have we attempted to analyze the tax burden that would be created by new entities called for under the current RTO West proposal, such as Scheduling Coordinators. There is a great deal of uncertainty about where such entities would form, how many there would be, and the level of income they would receive. However, it is clear that such entities may have substantial tax consequences for RTO West.

The availability of values based on plant investment for BPA transmission facilities on a state-by-state basis has allowed us to refine our estimates of tax liability. Despite the availability of these numbers, however, considerable uncertainty remains concerning how those assets would be valued, especially in the context of property and leasehold excise taxes. In particular, the values provided by BPA are for gross plant investment and do not include depreciation. With your agreement, we have added the estimated capital cost of the new transmission projects proposed by BPA as of February 2000 to the estimated value of BPA assets but have excluded the more recent planned "G-20" projects because of their uncertain funding prospects. Ultimately, the taxable value of RTO West's transmission assets is also likely to depend to a significant extent on the value determined under the income approach to valuation. As the application of this valuation method would require income and expense information that is not currently available (in part because RTO West does not yet exist and has no operating history), we have based our analysis on historic cost.

Notwithstanding the inherent uncertainty of projecting future capital costs and value, we believe our analysis provides a good approximation of what the value of BPA's transmission assets are likely to be a few years in the future. This would cover the period when RTO West is expected to be starting up and its initial years of operation. Given the substantial new investments planned and anticipated for the regional transmission grid, it is fair to expect the revenue requirement to support these facilities to grow substantially as well, which would increase the amount of RTO income upon which, for example, the Washington Public Utility Tax would be charged. We have not, however, attempted to estimate the additional revenues that would be associated with these new facilities, so our estimate of revenue and income-based taxes is likely to be low.

Despite these uncertainties, we believe our analysis is a reasonable approximation of the new state taxes that the region's ratepayers might face as a result of the formation of RTO West. Policy makers may wish to take these additional tax costs into account in evaluating the costs and benefits to the electric consumers of the proposed RTO system. In this context, it is interesting to note that our estimate of roughly $84 to $111 million in new leasehold and property taxes in Washington and Oregon comports closely with an initial estimate produced by BPA in August, 1999, which we understand suggested that the transfer of BPA assets to RTO West would create new property tax liability of approximately $105 million per year.

We note finally that this analysis is not intended to be a dispositive legal analysis on any issue. It is intended to provide only a general description of the tax consequences that might arise from formation of RTO West and should not be used as a conclusive evidence on any issue.

Very truly yours,

LANE POWELL SPEARS LUBERSKY LLP

George C. Mastrodonato

GCM:lm
Enclosure

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ANALYSIS OF TAX IMPLICATIONS OF RTO WEST IN WASHINGTON AND OREGON[1]

I. Overview and Assumptions

In our view, the major tax consequence arising from the formation of RTO West is likely to be that it will subject tax-exempt federal transmission assets owned by BPA to state and local taxation by virtue of the fact that BPA would hand operational control of those transmission assets to a non-federal entity, RTO West, that does not enjoy the same tax-exempt federal status. We recognize that similar changes will occur with respect to the control of the transmission investments owned by the investor-owned utilities that will become part of RTO West and that some of those utilities propose formation of a new entity, TransConnect, that would independently own and operate the transmission assets of some of those investor-owned utilities. Since those changes in ownership and control do not involve a transfer from a tax-exempt to a taxable entity, the tax consequences of the transfer of control are likely to be less severe, and for this reason we have not attempted to examine the tax consequences of those changes in ownership and operation of investor-owned utilities.

At this juncture, we have also limited our analysis to the tax laws of Oregon and Washington, where the bulk of BPA's transmission facilities are located. We recognize that a complete analysis would have to examine the tax consequences of RTO West in other states where the RTO would operate. In particular, an analysis of Idaho and Montana tax laws is necessary to complete the picture since substantial BPA transmission assets exist in those states. [2] The analysis presented here should be sufficient, however, to capture at least the major tax consequences that are likely to arise from formation of RTO West and the results under Oregon and Washington tax law should indicate what could be expected from a similar analysis of the tax laws in the other RTO West states. [3]

It should be noted, in addition, that we have attempted to make a high level estimate of the range of tax liability that would be associated with the formation of RTO West rather

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[1] This analysis was prepared by George C. Mastrodonato (JD, Gonzaga, 1976) and John H. Gadon (JD (with honors), University of Washington, 1983), who are partners in the law firm Lane Powell Spears Lubersky LLP, and by Nicholas P. Nguyen (JD, University of Washington, 1996), an associate at the Lane Powell firm. Assistance on questions related to Order No. 2000 and the form and structure of RTO West was provided by Eric Christensen (JD (with distinction), Stanford, 1987), Associate General Counsel, Snohomish County PUD.

[2] According to figures recently compiled by BPA, BPA has approximately $205 million worth of assets in Idaho and $330 million in Montana. Relatively small amounts of BPA assets are located in Canada, California, Nevada, Utah, Wyoming. *See* Exhibit A.

[3] BPA estimates that, on a gross plant value basis, 49.8% of BPA's transmission assets are located in Washington and 38.7% of those assets are located in Oregon. *See* Exhibit A.

than attempting to answer every legal question that would arise when the states attempt to tax the RTO. In particular, the question of valuation of transmission assets operated by the RTO is difficult to pin down exactly. Hence, we have included an estimated the range of likely tax impacts, rather than attempting to identify an exact outcome.

In estimating these tax impacts, we have used several estimates of the value of the Pacific Northwest transmission system, and BPA assets in particular. First, we have used figures compiled by BPA, which place the gross plant investment in its transmission system as of 2000 at approximately $4.8 billion, including approximately $2.4 billion of assets located in Washington and $1.875 billion located in Oregon. These figures are attached in Exhibit A. To these figures, we have added the slightly more than $1.4 billion in new transmission system upgrades BPA plans to add to its transmission assets in the 2000-06 time frame.[4] These figures are attached as Exhibit B. We have been advised that an estimated $700 million worth of these upgrades will occur in Washington and an estimated $542 million worth will be built in Oregon.[5] Hence, by 2006, we understand that, based on plant investment, the value of BPA's transmission system in Washington will be approximately $3.1 billion and its system in Oregon will have an estimated value of $2.4 billion.

Two important qualifications on these numbers should be noted. First, these figures are based upon gross plant investment and do not include any reduction in value due to depreciation. Since we have no way of reasonably estimating how depreciation of BPA's transmission assets, which would be a fact-intensive, facility-by-facility inquiry, would be factored into the tax valuation, we have not attempted to estimate this value. However, if substantial depreciation has occurred on the BPA transmission system, that may reduce the value of the transmission system for tax purposes, at least to the extent that the depreciation reduces the income-producing potential of the transmission assets.[6] Second, we note that BPA has recently proposed a series of 20 new upgrades to its

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[4] *See* Bonneville Power Administration, "BPA Projects Proposed for the 2000 to 2006 Timeframe," (posted March 16, 2000, at http://www.transmission.bpa.gov/tbllib/newsevnts/docs/capitalprogram3_16_00.pdf).

[5] We understand that these figures were derived by multiplying the BPA state percentages of plant investments, *see* note 3, *supra*, by the $1.4 billion in total additions planned for the 2001-06 period. The proposed BPA projects include both location-specific projects and general items. We have been advised that because of the bulk of general items, a good estimate could be made on the basis of state percentages of plant investments.

[6] We note that in the 2002 Transmission Revenue Requirements Study prepared for BPA's most recent transmission rate case, BPA claimed approximately $3 billion of book depreciation on a gross transmission plant investment, as of 2002, of $5.88 billion. *See* Bonneville Power Administration Transmission Business Line, 2002 Transmission Revenue Requirements Study, at Table 4.3 (March 2000) (sum of "depreciation" column) (www.transmission.bpa.gov/tbllib/ratecase/exhibits/TR-02-E-BPA-01_Final.pdf). We understand that this is straight-line accounting depreciation based upon the expected 40-year life of transmission assets. In our experience, historic cost less depreciation is one factor taken into account in valuing utility property for property tax purposes. However, depreciation computed for book purposes may differ significantly from depreciation used in computing value for property tax purposes as book depreciation may not reflect actual loss in value in terms of the income-generating capacity of the assets. The proper method of computing depreciation on utility property for property tax purposes and the amount of weight that should be placed on a cost approach to valuation in valuing utility property have been the subjects of extensive litigation.

transmission system, which it projects would be energized between 2002 and 2006, and has sought the participation of non-federal parties to support capitalization of the projects. The total value of these additional upgrades is over $1 billion.[7] Depending on whether these projects are built and whether they are booked to BPA's system or to the system of a co-funder, these projects would add another large increment to the value of BPA's system. Due to the current uncertainty about whether these projects will be funded, we have not included them in our estimates of BPA's future system value.

We have also been advised that BPA has a "fair market value" estimate for its transmission system of $8.3 billion, a figure which was published by BPA in its initial analysis of likely RTO impacts in 1999. Using the percentages BPA provided in its state-by-state analysis of its asset base,[8] this translates into a fair market value for BPA's transmission assets of about $4.1 billion in Washington and about $3.2 billion in Oregon. This estimate does not include the new transmission upgrades and additions discussed in the previous paragraph, which are likely to substantially increase the fair market value of the BPA transmission system.

Thus, based on BPA's gross plant investment and BPA's estimate of the transmission system fair market value, we estimate that the values of the assets in question range from $3.1 - $4.1 billion for Washington, and $2.4 - $3.2 billion for Oregon. We have based our estimates of Washington and Oregon tax liabilities on this range of values. Note that ultimately, the taxable value of RTO West's transmission assets is also likely to depend to a significant extent on the value determined under the income approach to valuation. As the application of this valuation method would require income and expense information that is not currently available (in part because RTO West does not yet exist and has no operating history), we have based our analysis on historic cost.

Where gross income serves as a basis for taxation, we have used the gross revenue requirements published by BPA and the other RTO West filing utilities in connection with the RTO West Pricing proposal. The Pricing proposal assumes an annual gross revenue requirement for BPA of a little more than $590 million, and a gross revenue requirement of a little more than $1.59 billion for the entire RTO West transmission system. The values will likely rise substantially as new additions to the transmission system come on line. However, we have not attempted to estimate the additional revenue requirements associated with these additions.

We have also assumed that RTO West would hold property, including office buildings, control centers, computers, and the like valued at $100 million, which is based on the range of start-up costs for existing RTOs in the preliminary cost-benefit analysis recently performed for RTO West by Tabors Caramanis & Associates ("TCA"). TCA estimated that RTO West's annual operating costs would be in the range of $126 million to $142 million. For purposes of our analysis, we have assumed an annual operating cost of $130 million.

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[7] For a description of the proposed projects, see the report posted online at: http://www.transmission.bpa.gov/tbllib/Publications/Infrastructure/default_files/slide0001.htm

[8] *See* note 3, *supra*.

Finally, we believe that, in addition to the tax consequences of transferring federal assets to a non-federal entity, certain other aspects of the RTO West proposal are likely to have significant tax consequences. In particular, we believe the establishment of new Scheduling Coordinators exposes the transmission revenues that would flow through the Scheduling Coordinators to potentially significant new taxation. However, given the uncertainty about how many independent Scheduling Coordinators would be formed, how many existing entities would establish their own internal Scheduling Coordinators, and the exact nature of the Scheduling Coordinator, we have not attempted to quantify the potential new tax exposure associated with these entities.

II. Factual Background: RTO West and the Northwest Electric Transmission System

"RTO West" is the name of the regional transmission organization ("RTO") that a coalition of transmission owners is working to develop in the Pacific Northwest and adjacent states and Canadian provinces. The territory to be covered by RTO West is referred to as the "RTO West Geographical Area."

The coalition of transmission owners currently working to develop RTO West consists of: Avista Corporation, Bonneville Power Administration ("BPA"), British Columbia Hydro and Power Authority, Idaho Power Company, the Montana Power Company, Nevada Power Company, PacificCorp, Portland General Electric Company, Puget Sound Energy, Inc., and Sierra Pacific Power Company. These transmission owners are often referred to as the "Filing Utilities." The Filing Utilities have been engaged in a collaborative process with a broad range of stakeholders since March 2000, to develop the proposal for RTO West.

RTO West is a nonprofit corporation formed under Washington state law. RTO West will be designed to qualify for RTO status under "Order 2000", which was issued by the Federal Energy Regulatory Commission ("FERC") on December 20, 1999. Among the features necessary to qualify as an RTO is independent governance. Independence means that the entity must not be subject to the control of entities that are in the business of buying and selling the electric energy that is delivered through the RTO's transmission system (often referred to as "market participants"). FERC has issued an order finding that RTO West's proposed governance structure satisfies the independence requirements established in Order 2000.

As currently envisioned, RTO West will not own transmission assets, apart from the facilities necessary for it to perform its system management functions. Instead, the RTO will operate transmission lines whose title ownership remains with the existing transmission owners, such as BPA. Some of the investor-owned filing utilities also plan to transfer ownership of their transmission assets to a newly formed transmission company, "TransConnect." TransConnect will then assign operational control of those transmission facilities to RTO West. The transfer of ownership of assets to

TransConnect is another element of the RTO West proposal that may have significant tax consequences, but we have not attempted to analyze them here.

The Filing Utilities will bring their facilities under RTO West's operational and pricing umbrella by signing an agreement known as a Transmission Operating Agreement or "TOA". Once RTO West begins commercial operations, it will provide transmission service across all of the high-voltage facilities of all of the companies and agencies that sign TOAs. RTO West's transmission service will be governed by a FERC-filed tariff (except in British Columbia, where service will be under a virtually identical tariff filed with the British Columbia Utilities Commission).

Although RTO West is a non-profit corporation and it may attempt to qualify for tax-exempt status, we have substantial doubts about whether it can qualify for an exemption from federal taxation under either Section 501(c)(3) or under other forms of tax exemption. If RTO West fails to qualify for tax exempt status, it would be subject to federal income tax on its net income. Since RTO West will be operated as a Washington non-profit corporation, we have assumed that it will not accumulate more than modest amounts of net income that would be subject to federal taxation. However, whether RTO West would have federal income tax liability would depend on a number of factors, including among other things: (i) timing of income and expense, and (ii) the percentage of its revenues that are used to purchase capital assets that are depreciated over a number of years rather than expensed in the year of purchase. Under certain circumstances, RTO West could operate on a non-profit basis and still have significant taxable income.

As noted above, RTO West would operate the electric transmission facilities owned by the Filing Utilities but would not take title to those facilities. Presently, BPA's Power Business Line takes the electric output from all the federal projects in the Columbia Basin and sells the power at wholesale to its wholesale customers and the Direct Service Industries using the BPA transmission system, which is operated by BPA's Transmission Business Line ("BPA-TBL"). Under RTO West, by contrast, operational control of the BPA transmission system would be assumed by RTO West, although BPA would retain title ownership of its transmission facilities. BPA would contribute the bulk of the transmission assets that would be operated by RTO West. Overall, BPA owns about 75% of the high-voltage transmission grid (230 kV and above) and about 50% of the lower-voltage transmission grid (115 kV) in the Pacific Northwest.

Under the current RTO West proposal, a number of new taxable entities may be created that raise the possibility of substantial new tax liabilities. For example, RTO West will require each generator and each load to use a Scheduling Coordinator to move power across the RTO West system. A few of the larger entities participating in RTO West may have the financial wherewithal to act as their own Scheduling Coordinator, but it appears likely that several new entities will be formed to act as Scheduling Coordinators for all the other parties who will be using the RTO West system.

The services to be performed by the Scheduling Coordinators are: (1) they will submit "balanced" schedules to RTO West, meaning that they will have to identify a power source for each load they schedule so that injections of power into the system for their schedule equals withdrawals; (2) they will collect all necessary billing information from their clients and submit it to the Paying Agent; and, (3) they will buy and sell balancing energy, reserve energy, and other "ancillary services" that are required to support the transactions they've scheduled. While it is difficult based on current information to estimate the number of Scheduling Coordinator entities that would be formed, where they would be located, and the amount of income they would receive, it is clear that such new entities would incur substantial tax liability. For example, as discussed further below, such entities would pay the Business and Occupation tax in Washington on their gross income or the corporation excise tax in Oregon, as well as federal income tax and other taxes such as property tax. Depending on factors such as the amount of gross income received by these entities, the location where they conduct business, and the extent to which Scheduling Coordinator functions are performed by new entities rather than in-house by existing entities, the total tax liability could be quite substantial.

III. RTO West and Washington State Tax Law

The Washington taxes of concern for RTO West which are discussed below are the public utility tax, property tax, leasehold excise tax, retail sales and use tax, and business and occupation tax. These taxes will be discussed below in the context of all the various entities identified above.

A. Public Utility Tax.

Under Chapter 82.16 of the Revised Code of Washington ("RCW"), all public utilities, including "light and power businesses" are subject to a Public Utility Tax ("PUT"). While RTO West would be different from the electric utilities that have traditionally operated in Washington in that it will not sell power but only transmission services, it nonetheless appears to fall squarely within the statutory definition of "light and power business." Under that definition, a business which is "operating a plant or system . . . for the wheeling of electricity for others" is a taxable "light and power business." RCW § 82.16.020(5). Since the RTO would be operating the regional transmission grid in order to wheel electricity across the grid for other parties, there appears to be little question that it would be considered a "light and power business" subject to the PUT.

Under the PUT, light and power businesses are taxed on their gross income at the rate of 3.62%. The statute provides a number of exemptions that the company may deduct from its gross income for purposes of computing the PUT, but only one of those exemptions appears to be potentially applicable to RTO West. Specifically, RCW § 82.16.050(9), allows a utility to deduct "[a]mounts derived from the production, sale, or transfer of electric energy for resale within or outside the state or for consumption outside the state." Since this exemption applies to the "electric *energy*" it has generally been understood to exempt only wholesale energy transactions from the PUT. For example, the Washington Department of Revenue ("DOR") interprets RCW § 82.16.090(9) in this way. If that is the case, RTO West would not qualify for the exemption because it is dealing in electric transmission capacity, not electric energy. Hence, there is a substantial possibility that the RTO would have to pay the PUT on its entire gross income.

Using the gross revenue figures for RTO West then, the RTO would have to pay a PUT of 3.62% on its gross income of approximately $1.59 billion, which amounts to approximately $57.5 million per year. In this case, formation of the RTO would result not only in taxation on the approximately $590 million of gross revenues currently received by BPA, but also an extra layer of taxation on the transmission transactions of the Investor-Owned Utilities ("IOUs") since the RTO would have to pay the PUT on its gross revenues, and the IOUs would have to pay again on the their revenues, which would include recovery of the costs of wholesale transmission paid to the RTO.

It is possible that the RTO will assert that at least some of its income is exempt from the PUT under RCW § 82.16.090(9), since its revenues derive from the "transfer" of electric energy and it is therefore entitled to deduct from its gross income the revenues it derives from transfers for "resale with or outside [Washington] or for consumption outside the state." Although it is not entirely clear how this exemption would be applied to the wholesale transmission transactions handled by the RTO, the RTO might be able to substantially reduce its tax liability to the extent it can be said that the transmission services it provides are subject to "resale." At a minimum, however, the RTO would have to pay taxes on the transmission services it would provide directly to Washington end users such as the Direct Services Industries.

If the RTO paid the PUT, it would not pay the Washington Business & Occupation Tax paid by ordinary corporations. It would, however, still be subject to other Washington taxes such as the property tax and the leasehold excise tax.

B. Property Tax

1. General Rules. RCW Title 84 imposes a property tax on all real and personal property unless the property is specifically exempt from tax. In Washington, property is assessed at one-hundred percent (100%) of its true and fair value. RCW 84.40.030. The rate of tax is the aggregate of levies approved for municipal, county, state, school district and other local taxing districts.

The basis for assessment of the operating and non-operating property of a public utility is the same as for property generally, i.e., true and fair value. For purposes of this analysis, we have assumed that RTO West will be taxed as a public utility. In valuing the operating property of a public utility, the Department of Revenue (which centrally assesses inter-county utilities) uses generally accepted appraisal principles applicable to the valuation of public utilities. The Department may consider any combination of the cost approach, the income approach, and/or the stock and debt approach in determining value. WAC 458-50-080. The cost approach determines the value of individual items of property based on historical, replacement, reproduction, and other cost measures. The income approach bases value upon a discounted present value of an income stream over a span of years. The stock and debt approach determines the value of assets by appraising the value of the liabilities of the company and stockholder's equity. Id.

Once the total value of the utility's property in Washington is determined, the value will then be apportioned to the different counties in Washington where property is located for determination of the property tax due in each county. The total property tax rate varies from county to county, and from taxing district to taxing district, but on the whole the statewide average levy rate is about 1.5 percent.

2. Transfer from exempt to taxable entities. Property that is exempt from taxation because it was owned by the United States, the State of Washington or a political subdivision thereof, or because the property was owned by an entity specifically exempt from taxation (see subsection 4 below), becomes assessable and taxable when transferred to private ownership. RCW 84.40.350. The transferred property is subject to a pro rata portion of the taxes allocable for the remaining portion of the year after the date of execution of the instrument of sale, contract, or exchange. RCW 84.40.360. In some cases, a rollback of taxes applies also. RCW 84.36.262 and 84.36.810. The property is listed and assessed by the assessor or, in the case of centrally assessed utilities, by the Department of Revenue, based on the property's value on that date.

3. Other exemptions from Washington property tax. Under RCW 84.36, the property tax does not apply to property held by certain non-profit corporations for a variety of purposes, such as public art or performance, charitable work, fraternal society, hospitals, religious use, medical research, day care, senior housing, etc. However, none of these exemptions would apply to RTO West and, furthermore, RCW 84.36 contains no exemption for which RTO West would qualify. So, all property owned by RTO West would be subject to Washington's property tax.

There are broad statutory exemptions for public property used by public or municipal entities in Washington, including municipal-owned electric utility property. RTO West is a private corporation rather than a public or municipal entity. Thus, RTO West would not qualify for the public property tax exemption.

In general, Washington property tax only applies to real property, tangible personal property and some limited types of intangible personal property. See RCW 84.36.070. In this case, we understand that RTO West will not own or hold title to any real or personal property that make up the transmission lines or associated transmission facilities in the system such as substations. Thus, there would not be a property tax payable by RTO West on these assets.

RTO West would own at least some transmission-related assets, however, such as computer systems, scheduling facilities, and control centers, and it likely would also own non-transmission assets, such as buildings and grounds. It would owe a property tax on these assets. Although the formula or appraisal methodologies for calculating the true and fair value of centrally assessed utilities is complex, as noted above on average one could expect to pay a property tax of approximately 1.5 percent of the property's true or fair market value on a statewide basis. So if RTO West were to own scheduling and control facilities and non-transmission real and personal property in Washington with a true and fair value of $100 million, its annual property tax bill for this property could be in the neighborhood of $1.5 million.

RTO West would not escape taxation for those assets it does not own, however. For the reasons discussed below, RTO West will more than likely be subject to the Washington leasehold excise tax on the publicly owned (BPA) transmission system assets RTO West does not own but are under its control in Washington.

C. <u>Leasehold Excise Tax</u>.

1. <u>General Rules</u>. As noted above, real and personal property used in a trade or business are subject to property tax in Washington. RCW 84.36.005. Under RCW 84.36.010, property owned by a governmental entity (such as the United States government, the State of Washington, a county or a municipal corporation in Washington) is not subject to property tax. When such publicly-owned property is leased (or possession and use is otherwise granted) to a private person, Washington imposes a leasehold excise tax on the lessee.

The term "leasehold interest" is broadly defined to include any "interest in publicly owned real or personal property which exists by virtue of any lease, permit, license, or any other agreement, written or verbal, between the public owner of the property and a person who would not be exempt from property taxes if that person owned the property in fee, granting possession and use, to a degree less than fee simple ownership". RCW 82.29A.020(1). The leasehold excise tax is thus intended to be a substitute for the property tax where a private party not otherwise exempt from the property tax (such as RTO West) uses and occupies the public property.

Further, the RTO West Transmission Operating Agreement ("TOA") appears likely to be the kind of "agreement" that grants an interest in the "possession and use" of BPA property that would subject RTO West to the leasehold excise tax. In essence, the TOA entirely transfers day-to-day control of the BPA transmission system to RTO West, and, in addition, transfers substantial authority to RTO West for longer-term control of those facilities by assigning to RTO West substantial authority over planning and expansion of BPA facilities, coordination of outage schedules, and the like. Indeed, to achieve the "independence" requirement of Order No. 2000, RTO West must operate free from BPA's control. Hence, there is a substantial likelihood that RTO West will be subject to the leasehold excise tax by virtue of its operational control over BPA assets in the State of Washington. Further, it is likely that RTO West will be determined to "possess" the entire BPA transmission system since it would use the entire system to provide transmission services to its clientele.

The leasehold excise tax is imposed at a rate of 12.84%. RCW 82.29A.030. Credits are allowed for any local leasehold excise taxes paid pursuant to RCW 82.29A.040 and also in an amount, if any, by which the leasehold excise tax exceeds the property tax that would apply to such leased property if it were privately owned. RCW 82.29A.120(1). Thus, the leasehold excise tax is designed to approximate what the property tax would be if the lessee owned the property in fee.

The leasehold excise tax is imposed on "taxable rent" (RCW 82.29A.030), which ordinarily includes the rent payments set forth in the contract ("contract rent") (RCW 82.29A.020(2)(a)), provided that the leasehold interest was established through competitive bidding or a similar process. (RCW § 82.29A.020(b)). In this case, however, RTO West would not be required to pay any consideration for assuming control over BPA's transmission facilities. Hence, it is likely that the Washington Department of Revenue would assign a value to RTO West's leasehold interest in BPA's transmission system based upon "a fair rate of return on the market value of the property" subject to the leasehold interest. (RCW § 82.29A.020(b)(ii)).

Although it is difficult to estimate the leasehold excise tax due using the above criteria, the most likely outcome is that the leasehold excise tax will approximately equal the property tax that would be owed if BPA transmission assets were privately held. As noted above, RCW 82.29A.120(1) allows a credit against the leasehold excise tax equal to the amount that the leasehold excise tax exceeds the property tax that would otherwise apply to the property. So the maximum amount of leasehold excise tax payable by RTO West would be the amount of the property tax due on the property. Thus, one can determine the approximate amount of leasehold excise tax that would be imposed on the property by calculating the approximate amount of property tax, because that would be the maximum amount of leasehold excise tax payable in any event.

As noted above, the property tax on average, is imposed at a rate equal to 1.5 percent multiplied by the true and fair value of the property. If we use BPA's "fair market value" estimate of $4.1 billion for its Washington transmission assets as an approximation of the "fair rate of return on the market value of the property" subject to the leasehold excise tax, the annual tax liability would be approximately $61.5 million. On the other-hand, if we use the $3.1 book value of BPA assets to approximate the value subject to the leasehold excise tax, the annual tax liability would be approximately $46.5 million per year. Hence, we believe RTO West would be subject to a leasehold excise tax in Washington in the range of $46.5 to $61.5 million per year. The amount of tax actually owed by RTO West could be higher or lower depending on the actual true and fair value of the BPA assets located in the state of Washington, or the calculation of the leasehold excise tax by the Department of Revenue under RCW 82.29A.020(2)(b). However, we believe our estimate approximates the range of the expected annual leasehold excise tax bill that could be imposed on the BPA assets located in Washington which will be under the operational control of RTO West.

2. <u>Operating Properties of Public Utilities</u>. RCW 82.29A.130(1) provides an exemption from the leasehold excise tax for any leasehold interest constituting a part of the operating properties of any "public utility" which is assessed and taxed as a public utility. WAC 458-29A-400(2). If property does not qualify for the public utility exemption from leasehold excise tax, the public utility leasing the property would be

subject to the leasehold excise tax. But if property is eligible for the public utility exemption from leasehold excise tax, such property will instead be subject to property tax.

Accordingly, the BPA assets held by the RTO would be subject to the leasehold excise tax since BPA is not a "public utility" (*i.e.*, an ordinary investor-owned utility) within the meaning of the statute. Most of the remaining transmission assets over which the RTO would have operational control most likely would not be subject to the leasehold excise tax because they would be considered the operating properties of the investor-owned public utilities that own the facilities. The underlying public utility would pay property tax on those assets, as it does now, and the RTO would not be required to pay a leasehold excise tax on those assets. The only complication that could arise is if the transfer of operational control of the assets could be said to remove them from the investor-owned utilities' "operating properties."

3. Additional issues arising under leasehold excise tax. To the extent that the leasehold excise tax applies, leasehold excise tax will generally be collectible from the private lessee, in this case RTO West. There are two exemptions from the leasehold excise tax that, at first glance, appear potentially applicable to the RTO. On closer examination, however, it is clear that neither exemption would apply. Specifically, the two exemptions from the leasehold excise tax are for situations where either (i) a private owner has use or occupancy of public property if the purpose of such use or occupancy is to render services to the public owner (see WAC 458-29A-100(2)(f)(iii)), or (ii)) to the extent that the use and possession of public property is solely with respect to a "Management Agreement" as defined in the rules (WAC 458-29A-100(2)(j)).

It appears unlikely either exemption would prevent the imposition of the leasehold excise tax on RTO West. The exemption for private parties who provide services to the public owner of the facility is unlikely to apply because RTO West will provide a variety of services to all parties using the Northwest transmission grid. The exemption, by contrast, applies only where the public owner of the facility is the sole recipient of the services rendered by the private party. WAC 458-29A-100(f)(iii).

Nor would the exemption for a "Management Agreement" apply. This exemption applies only if three specific criteria are met and RTO West appears to meet none of them. The first criterion is that the public property owner "retains all liability for payment of business operating costs and business related damages." WAC 458-29A-100(j)(i). Under RTO West, however, users of the RTO-controlled transmission system, rather than BPA, would have the primary liability for the operating costs of the transmission system. The second criterion is that the public property owner must retain the "full discretion whether to eliminate, reduce or expand the business activity conducted on the property." WAC 458-29A-100(j)(ii). Under RTO West, BPA would retain little or no control over decisions to eliminate, reduce, or expand the transmission services offered over its system. The third criterion is that the public property owner has "full control of the prices to be charged for the goods or services provided in the course of use of the property." WAC 458-29A-100(j)(iii). Under RTO West, the prices charged for transmission services provided over the BPA system would be set by a RTO West tariff subject to the approval of FERC. Hence, BPA would have substantially less than "full control" over those prices.

D. Retail Sales Tax/Use Tax.

The retail sales tax is imposed on each retail sale in Washington. RCW 82.08.020. The use tax is generally imposed on property used in Washington and upon which the retail sales tax has not been imposed. RCW 82.12.020. The use tax is significant in the context of RTO West because the Washington retail sales tax has presumably not been paid by BPA on any of its Washington assets (because the United States Government is exempt from the Washington sales or use tax). However, when BPA allows RTO West to use its assets, the Washington use tax will likely be triggered.

Since BPA will not be transferring title to its Washington assets to RTO West, the assets will likely be subject to use tax under the "bailment" provisions of Washington's use tax law. Bailment occurs when property which has not been subjected to sales or use tax is used in Washington for essentially no consideration. In a bailment situation, the use tax is measured by the reasonable rental value of the property bailed. RCW 82.12.010(1)(b); WAC 458-20-178(13).

With the information presently available, it would be extremely difficult to calculate the reasonable rental value of BPA's Washington-based assets. In addition, the Department would not apply use tax on the property's reasonable rental value if sales or use tax has been paid on the property. Here, because RTO West's use of the BPA transmission assets is presumably long-term, it may be prudent for RTO West to pay a one-time use tax on the full value of the BPA assets transferred to use by RTO West, rather than reasonable rental value attributed to periodic lease payments ad infinitum, because this latter amount could, over time, lead to tax payments that could far exceed the value of the assets.

If the RTO followed this course, using our \$3.1 to \$4.1 billion estimate of value for BPA's Washington assets, the use tax at a hypothetical eight percent (8%) on these assets would be in the range of \$248 to \$328 million.

E. Business and Occupation Tax.

As noted above, RTO West will most likely to be subject to the PUT, which would mean that it is exempt from the Washington Business and Occupation ("B&O") tax. However, if it is determined that RTO West is not a "light and power business" subject to the PUT, it would instead be subject to the B&O tax. Other RTO-related entities in Washington, such as Scheduling Coordinators, will also be subject to the B&O tax.

The B&O tax is a tax on "the act or privilege of engaging in business activities". RCW 82.04.220. The B&O tax is "measured by the application of rates against value of products, gross proceeds of sales, or gross income of the business, as the case may be". RCW 82.04.220.

The B&O tax on businesses like RTO West is imposed under the "other business or service activities" classification. RCW 82.04.290(2); Washington Administrative Code (WAC) 458-20-138 and 458-20-224. This tax is measured by the "gross income of the business". RCW 82.04.290. Gross income "means the value proceeding or accruing by reason of the transaction of the business engaged in". RCW 82.04.080. Value proceeding or accruing "means the consideration . . . actually received or accrued". RCW 82.04.090.

To estimate the estimated B&O tax for the RTO, the expected revenue of the RTO, approximately $1.59 billion, is multiplied by the current B&O tax rate of 1.5 percent. This results in an estimated tax liability of approximately $23.8 million per year. Hence, if the RTO escapes the PUT, which we estimate to be approximately $57.5 million per year, it would still have to pay a B&O tax of approximately $23.8 million. Cities are also allowed to impose their own B&O taxes. So, if RTO West is located in a city that imposes a B&O tax, then RTO West would likely have to pay an additional B&O tax to the city in which it is located.

The B&O tax would also be imposed on the gross income or fees of the Scheduling Coordinators and Paying Agent that are part of the RTO West structure as currently proposed. At this juncture, it is very difficult to reliably predict what the taxable gross income for these entities would be. But, as noted above, the gross income of each entity located in Washington would be taxed at the rate of 1.5 percent. One can simply multiply their anticipated or expected gross income times the current B&O tax rate of 1.5 percent.

The above discussion on the B&O tax assumes that RTO West and the other entities are doing business in Washington only, and their only places of business are located in this state. But if they have places of business outside Washington, the Washington B&O tax may be apportioned. RCW 82.04.460. Apportionment is generally based on a formula which essentially calculates Washington costs and total costs multiplied by gross income. So, for example, if Washington costs account for seventy percent (70%) of total costs of operation, 70% of gross income would be taxable in Washington. It would appear that at least RTO West might be allowed to apportion its income for B&O tax purposes since it will have transmission facilities in more than one state and, presumably, offices or other places of business in those other states to support those facilities. Thus, RTO West's gross income might be subject to apportionment, thereby reducing its Washington B&O tax liability.

IV. RTO West and Oregon Tax Law

A. Brief Conclusions and Estimates

Oregon does not have a sales or use tax. At the state level, the Oregon taxes of concern for RTO West are property and corporate excise (income) taxes. In addition, there are also business license fees and taxes in the city of Portland and the surrounding Multnomah County that are based on net income.

There is a substantial risk that RTO West will be subject to property tax on the value of the transmission system under its control in Oregon. Based upon our rough estimate that BPA transmission assets would be valued at roughly $2.4 to $3.2 billion, RTO West would be subject to Oregon property taxes of roughly $36 to $48 million annually.

In addition, RTO West will probably be subject to Oregon corporation excise tax (at the rate of 6.6%) on its Oregon taxable income. As noted above, the RTO will be operated on a non-profit basis and we have assumed, for purposes of this memorandum, that it likely will not have significant income tax liability at the federal level. Since the starting point for determining a corporation's Oregon corporation excise tax is its federal taxable income, RTO West's Oregon corporation excise tax liability is also likely to be relatively small. The Oregon corporation excise tax could result in significant liability, however, upon Scheduling Coordinators and other new RTO-related entities doing business in Oregon.

Similarly, business license fees and taxes in the city of Portland and the surrounding Multnomah County that are based on net income could result in significant tax liability for such entities.

B. <u>Oregon Property Tax</u>.

1. <u>No exemption from Oregon property tax</u>. Under the Oregon Revised Statutes (ORS), property tax does not apply to property held by certain non-profit corporations for a variety of purposes, such as public park or recreation, charitable work, fraternal society, religious use, senior housing, etc. However, none of those exemptions applies to RTO West.

There is also a broad statutory exemption for all public and corporate property used by public or municipal entities in Oregon, including municipal electric utility property. ORS 307.090. In this case, RTO West would operate as a private non-profit corporation rather than as a public or municipal entity. Thus, RTO West does not qualify for this public property tax exemption.

In general, subject to the discussion below regarding the taxation of utilities, Oregon property tax only applies to real property and tangible personal property. ORS 307.030(1). In this case, RTO West will likely own office buildings, major software and computer hardware, control centers, and the like. As noted above, if the RTO is located in Washington, it would incur annual property tax liability of approximately $1.5 million per year. If it is instead located in Oregon, roughly the same property tax liability would result because the property tax rates in the two states are comparable, approximately 1.5% of assessed valuation. The RTO will not, however, own or hold title to transmission lines and associated facilities such as substations. Nevertheless, for the reasons discussed below, there is substantial risk that RTO West might be subject to Oregon property tax on any the transmission lines and related systems in Oregon under its control.

2. RTO West subject to property tax on BPA transmission system under its control. As a transmission service provider, RTO West would probably be subject to the special property tax assessment rules applicable to public utilities, ORS 308.505 to 308.665. (The definition of a utility includes a company performing or maintaining an electricity "business." ORS 308.515(1)(a)). Under these special rules, an electric utility is assessed by the Oregon Department of Revenue (ODR) rather than by the county assessors. Moreover, with a few exceptions that are not applicable to this case, any property used or held for future use by RTO West in performing or maintaining its electric utility services would be subject to assessment. ORS 308.505(1)(a), 307.030(2). Property for this purpose includes all real and personal property, whether tangible or intangible, that is used or held by the taxpayer as owner, occupant, lessee or otherwise for the performance of its business or service. ORS 308.510(1).

Thus, RTO West would be subject to tax not only on the property it actually owns in Oregon, such as its control centers, office buildings, and the like, but it could also be subject to property tax on the transmission system over which it exercises operational control in Oregon, on the theory that such control represents a taxable intangible property, or that RTO West holds the transmission system under the equivalent of a lease or right of occupancy.

With respect to the BPA transmission system in Oregon that will be under operational control by RTO West, the ODR could also argue that RTO West should be subject to Oregon property tax under ORS 307.060, regardless of whether it is treated as a public utility.

Specifically, property held by the federal government is exempt from Oregon property tax. ORS 307.040. However, property owned by the federal government but held by a taxable entity under a lease or other interest not amounting to a fee simple can be assessed at its full value against the taxable user. ORS 307.060. The ODR could argue that because RTO West will have effective and exclusive operational control over the BPA transmission grid in Oregon, it should be assessed on the full value of such transmission system, subject to any deductions for applicable restrictions.

In *Power Resources Cooperative v. Department of Revenue,* 330 Or 24 (2000), *aff'g* 14 Or Tax 479 (1998), an electrical cooperative had a capacity ownership agreement with BPA that gave the cooperative 50 MW worth of transmission capacity for the physical life of the Intertie, an electric power transmission system interconnecting the BPA system to California that is largely owned and operated by BPA. The Oregon Department of Revenue argued, and the Oregon Tax Court and the Oregon Supreme Court agreed, that the taxpayer had sufficient exclusive control over a part of the Intertie transmission system, and thereby should be subject to property tax under ORS 307.060 as a holder of a lease or similar interest in federal property.

In *Power Resources,* BPA retained all rights to operate, maintain and manage the Intertie. However, for an advance lump sum payment and a share of the operating, maintenance and replacement expenses for the Intertie, the taxpayer was entitled to 50 MW of capacity at any given time, subject to applicable scheduling procedures. The taxpayer could use that capacity to transmit electrical power that it produced or purchased, or it could use that capacity to "wheel" electricity for other entities. Any unused, i.e., unscheduled, capacity could be used by BPA, but if BPA were to use such unscheduled capacity, BPA would be obligated to compensate the taxpayer.

The Oregon Supreme Court acknowledged that ORS 307.060 applied only to a possessory interest, pursuant to *Sprout et al v. Gilbert et al,* 226 Or 392 (1961). The court found that possessory interest is based on a certain degree of control and exclusive use, which could vary depending on the nature of the property at issue. Although the Intertie contract right in that case did not confer the same kind of exclusive control or occupation over a specific portion of property that is characteristic of a possessory interest in real property, the court concluded that the exclusive right to use and control the transmission system to the extent of 50 MW was sufficient to qualify as a possessory interest in the Intertie for property tax purposes. The court therefore concluded that the taxpayer "held" a share of the property that made up the Intertie, and may be assessed and taxed for that share to the extent provided by law.

Given the *Power Resources* precedent, it appears unlikely that RTO West could avoid paying property tax on the BPA transmission assets it would control in Oregon. This is because RTO West would have more substantial control over the BPA assets than did the taxpayer in *Power Resources.* Specifically, RTO West would have the right to control and manage transmission on the BPA system in Oregon, rights which the taxpayer in *Power Resources* did not have. Hence, RTO West's rights would be even more substantial than the rights held to trigger property taxes in the *Power Resources* case. We note, however, that the *Power Resources* precedent is subject to further litigation brought by other holders of transmission capacity contracts on the Intertie, so *Power Resources* may not be the last word on this subject.

3. Estimate of property tax liability. Several questions arise with respect to the valuation of BPA transmission assets for the purposes of taxing RTO West's use of those assets. First, if RTO West is treated as a public utility, the ODR might choose to value RTO West as an operating unit under the unit method allowed by ORS 308.555, and then allocate a portion of that total value to Oregon. The valuation process is complex and generally relies on the three traditional approaches based on market comparison, cost and income. *See e.g.,* OAR 150-308.205-(B); *Pacific Power & Light Co. v. Department of Revenue,* 308 Or 49 (1989). Allocation may depend on different factors such as production and distribution capacities in Oregon, as measured by a weighted average of original cost, kilowatt-hours, and revenue. OAR 150-308.550(2)-(C). This operating unit computation might yield a different valuation.

Second, the assessed value for Oregon property tax purposes is subject to certain constitutional limitations designed to keep the keep assessments within certain modest annual increases from the 1995 level. Valuation for new property on the tax roll is thereby subject to certain modification to reflect the general ratio of average assessed value to average real market value for the year.

Once assessment is complete, the assessed value will then be apportioned to different counties in Oregon for determination of the property tax due. The applicable property tax rate can vary from county to county, as well as between different taxing districts within a county. There is a general constitutional cap for school and local government operating levies of $15 to each $1,000 of assessed value, although certain bond and other local levies are not subject to this constitutional cap. The actual levy amount varies by tax code area. In the city of Portland, the consolidated tax rate is approximately $22 per $1,000 of assessed value. Assuming property tax at the operating levy cap of $15 to each $1,000 of assessed value, our rough value estimate of $2.4 to $3.2 billion of BPA transmission assets located in Oregon would yield an aggregate property tax bill of about $36 to $48 million annually.

C. Oregon Corporation Excise Tax.

The application of the Oregon corporation excise tax is summarized as follows.

ORS 317.070 provides that any public utility that is subject to central assessment for property tax purposes, and every mercantile, manufacturing and business corporation doing business in Oregon, will be subject to an excise tax on its Oregon taxable income, unless specifically exempt by the statute. The tax rate is currently 6 and 6/10 percent. ORS 317.061. The corporation excise tax is effectively an income tax that a corporation has to pay for doing business in Oregon.

The starting point is generally the federal taxable income of the corporation, subject to some additions, subtractions, adjustments and modifications specific to Oregon. As discussed above, we have assumed for purposes of this memorandum that RTO West's taxable income, if any, would be small and its corresponding tax liability would also be small. However, if RTO West uses revenues to acquire substantial capital assets that must be depreciated over a period of years, its expenses would not entirely offset its income, which could result in greater Oregon corporation excise tax liability. For Scheduling Coordinators and new entities that may be created as a result of RTO West, the Oregon corporation excise tax could create substantial tax liability. For the reasons noted in connection with our analysis of the Washington B&O tax, we have not attempted to quantify that liability here.

D. RTO West and Local Oregon Taxes.

There are also several local Oregon taxes of potential importance to RTO West and related entities. We do not treat these taxes in detail here, but it is worth noting that, for example, the City of Portland imposes a gross receipts tax of 5% on "public utilities" doing business with city limits and a business license fee of 2.2% of net income apportioned to the City of Portland for other types of businesses. Similarly, Multnomah County, Oregon imposes a 1.45% tax on net income on businesses operating within the county, based on income apportioned to the county.

This table was first posted February 14, 2000. It has been modified here at the request of Lon Peters to show the voltage levels of the various projects.

BPA PROJECTS PROPOSED FOR THE 2000 TO 2006 TIMEFRAME

		NEED	EXPENDITURES X$1000						
PROJECT	**NEED FOR PROJECT**	**DATE**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**
SEATTLE AREA SUPPORT PROJECTS									
East Seattle Reinforcement (Raver-Echo Lake 500-kV line)	Meet load growth in Seattle and to the north, and return Entitlement to Canada	2002	1024	16166	538				
North Seattle Transformer (Sno-King 500/230-kV Txf)	Meet load growth north of Seattle	2002	307	9908	2412				
Schultz Series Caps 500-kV	Meet load growth in Puget Sound region and return Entitlement to Canada (delays need for cross cascades line)	2003		104	10931	16979			
Cross Cascades Line (new 500-kV line) (1)	Meet load growth in Puget Sound region and return Entitlement to Canada	2008						1164	4780
PORTLAND AREA SUPPORT PROJECTS									
Pearl 500/230-kV Transformer	Meet load growth in SW Portland area	2005					2268	15132	
Big Eddy Tap (500-kV) to Hanford-Ostrander Line (2)	Meet load growth in greater Portland area (delays need for cross cascades line)	2007						1164	1195
INCREASE RATING OF CONSTRAINED PATHS									
Northern Interconnection (500-kV)	Accommodate increased transfer of power from Canada	2003		2968	28691	8997			
West of Hatwai Path (230-kv)	Accommodate increased transfer of power from Montana, Northern Idaho and Eastern Washington	2003		2086	10770	41952			
West of McNary Path (500-kV)	Accommodate transfer of new generation in Hermiston area to load areas	2003 and 2006		1043	2154	7728			2390
PNW-Idaho Path (230-kV)	Accommodate increased transfer of power to Idaho	2002		522	2692				
AREA SERVICE PROJECTS									
Reactive Support (500-kV, 230-kV & 115-kV)	Meet load growth in various areas	various	10495	5000	5000	5000	5000	5000	5000
Central Oregon Coast (115-kv)	Meet load growth in Grande Ronde and Lincoln City areas	2002		209	2800				
Eastern Idaho (161-kV)	Meet load growth in NE Idaho and Wyoming	2002		209	2208				
Kitsap Peninsula (230-kV)	Meet load growth in Bremerton Area	2002	102	1043	12170				
Longview Area (230/115-kV transformer)	Meet load growth in Longview area	2006						233	4541
Northwest Idaho/Western Montana (115-kV)	Meet load growth in same area	2006						582	6573
Olympic Peninsula (230-kV)	Meet load growth in Olympic Peninsula	2004				1104	5670		
Salem Area (230-kV)	Meet load growth in Salem area	2006					567	1746	10755
Southwest Oregon Coast (230-kV)	Meet load growth in Coos Bay area and south coast	2004		376	6917	19870	6804		
Olympia (230/115-kV transformer)	Meet load growth in Olympia area	2006						931	2390
Spokane Area (3) (230/115-kV transformer)	Meet load growth in Spokane area	2007							239
Misc. Area and Customer Service Projects (230-kV and 115-kV)	Meet load growth in various areas (includes several small projects)	various	2048	2086	4308	4416	4536	4656	4780

(1) This project also includes expenditures of $73,792 in 2007 and $76,006 in 2008

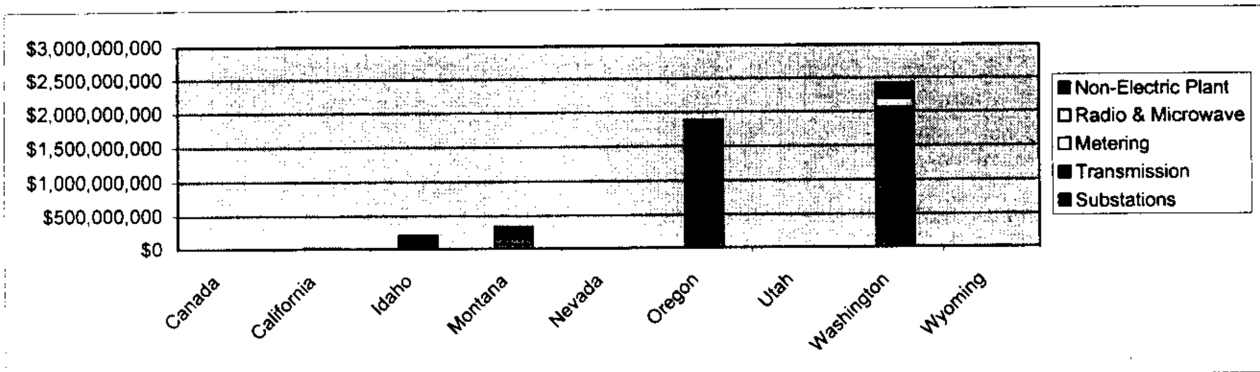
(2) This project also includes expenditures of $15,988 in 2007

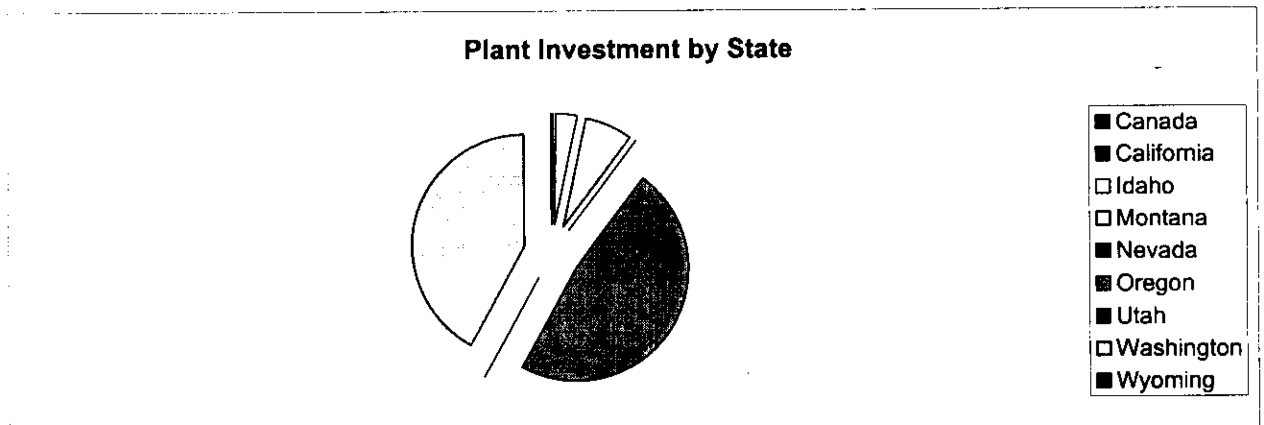
(3) This project also includes expenditures of $5,903 in 2007

		NEED	EXPENDITURES X$1000						
PROJECT	NEED FOR PROJECT	DATE	2000	2001	2002	2003	2004	2005	2006
FY2000 AND FY2001 PROJECTS									
Raver-Paul outage relief (230-kV)	Accommodate increased transfers from Canada	2001	512	3650					
Olympia-White River Relocation (230-kV)	Relocate line due to easement termination	2001		521					
Northern Intertie Fixes (230-kV)	Increased transfers with Canada	2000	6306						
Hood River Reinforcement (115-kV)	Meet load growth in Columbia Gorge area	2000	2048						
San Juan Cable Replacemt (69-kV)	Service to San Juan Islands	2001	469	10284					
Albany-Eugene Rebuild (115-kV)	Meet load growth in Albany area	2001	1229	3129					
Trentwood Area (230/115-kV transformer)	Meet load growth in Spokane area	2001	102	871					
Franklin Area Reinforcement (115-kV)	Accommodate transfer of new generation from Hermiston area to load areas	2000	3174						
Tanner (115-kV)	Meet load growth in North Bend area in Washington	2000	2048						
Midway-Grandview Reconductor (115-kV)	Meet load growth in Sunnyside, Grandview and Benton City areas	2001	410	3859					
N-2 COMPLIANCE		various	4096	4172	4308	4416	4536	4656	2390
VARIOUS ADDITIONS		various	5000	10000	10000	10000	10000	10000	10000
SYSTEM CONTROLS		various	7168	8344	8616	8832	9072	9312	9560
MISC LINE AND SUB ADD		various	5120	3995	4233	4449	5670	6984	7170
FIRE SUPPRESSION		various	0	1043	1077	1104	1134	1164	1195
TRANS SCHED & BILLING		various	10145	5225	4346	2346	3203	3754	3585
NONELECTRIC REPLACMTS		various	1024	1304	11309	6072	3969	5238	5378
REPLACMENT PROJECTS		various	22221	28672	30769	30652	32953	47002	37732
PCB CAP REPLACEMENTS		various	9086	9086	9047	9274	9526	9778	10038
FIBER		various	31130	30769	27033	15500	10319	7449	7170
TOOLS AND EQUIPMENT		various	2560	4172	4308	4416	4536	4656	4780
EMERGENCY FUNDS		various	10000	10000	10000	10000	10000	10000	10000
OTHER DIRECT CAPITAL			-6704	2100	-2246	-2227	-2206	-2185	-2164
INDIRECTS			32055	31741	29294	29808	30618	31428	32265
AFUDC			4390	4690	5040	5225	5045	5105	5330
	TOTAL		167565	219347	248725	245913	163220	184949	187072

Plant Investment by State

	Substations	Transmission	Metering	Radio & Microwave	Non-Electric Plant	Total	
Canada	$0	$16,673	$0	$0	$0	$16,673	0.0%
California	$5,106,338	$10,602,929	$350,971	$141,911	$6,803	$16,208,952	0.3%
Idaho	$67,721,098	$129,120,640	$2,262,517	$6,074,403	$299,867	$205,478,525	4.2%
Montana	$159,539,457	$160,430,613	$842,991	$2,948,754	$6,749,695	$330,511,510	6.8%
Nevada	$0	$0	$205,341	$0	$0	$205,341	0.0%
Oregon	$1,063,285,737	$705,670,718	$13,516,815	$17,768,998	$75,661,301	$1,875,903,570	38.7%
Utah	$577,380	$0	$34,827	$0	$0	$612,207	0.0%
Washington	$937,775,164	$1,103,675,861	$6,003,941	$142,160,498	$226,090,230	$2,415,705,694	49.8%
Wyoming	$2,646,416	$1,874,374	$8,654	$0	$0	$4,529,444	0.1%
Total	$2,236,651,591	$2,111,391,810	$23,226,057	$169,094,564	$308,807,897	$4,849,171,918	100.0%
	46.1%	43.5%	0.5%	3.5%	6.4%		





February 22, 2002

Assessing the Reliability Impact of a Regional Transmission Organization (RTO)

Author: Edmund O. Schweitzer, III PhD
Contributor: Jeffrey B. Roberts

Assignment

At the request of Vickie Van Zandt, Vice President of Transmission Planning at the Bonneville Power Administration (BPA), we rapidly analyzed the potential reliability impacts of establishing an RTO in the northwest part of the United States. The work spanned less that two months of time, and was conducted in a series of meetings in Vancouver, BC, a Relative Reliability Effect Analysis session in Pullman, WA, a briefing in Portland, OR, and report preparation in Pullman.

Re-regulation of the U.S. utility industry is well underway, with the changes being driven by Federal Energy Regulatory Commission (FERC) orders and deadlines. One of the difficulties in assessing reliability impacts of an RTO is keeping in mind exactly where we stand today. We no longer have a vertically-integrated utility structure, i.e., Generation, Transmission, and Distribution inside a single company franchised in a single geographic area.

We have moved to a state where generation is rather deregulated. The transmission assets continue to be regulated and operated by regional franchisees, in general. Here in the Northwest, the Bonneville Power Administration network crosses the boundaries of the franchisees and handles much of the transmission of electric power.

Planning used to be a company activity, coordinated in the region between companies. This planning was holistic within the franchised company--covering generation, transmission, distribution, and the needs of customers. Today, individual generators are developing their plans in private, and are expecting the transmission grid to handle the power.

Given that FERC has directed the industry to come up with four to five RTOs covering the United States, it seems that there is little choice but to form RTOs. Consequently, this analysis mainly assumes that an RTO will be formed, and attempts to identify where difficulties may be experienced. We have also taken a first estimate as to how to mitigate any difficulties.

Therefore, we stress that this report is not a pros-vs-cons-of-an-RTO discussion. Instead, the report attempts to determine the impacts and risks in moving from the present hyper-state in the re-regulation process, towards a state envisioned by FERC, where deregulated generators supply energy into a more regulated transmission system/marketplace, and where this transmission system would be managed by a new organization, above the existing organizations of the utilities owning transmission today.

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Another present characteristic to keep firmly in mind is that essentially no new transmission has been built in the past 15 years, and the once-conservative system is now stressed at several points. A once-supple system is now brittle.

Fortunately, BPA finally received Congressional approval to borrow $750M of the $2B it requested to build more transmission. Just as fortunately, it appears that the bottleneck at Path 15 will be relieved with about $30M of new transmission.

Thus, our approach was to try to understand the present situation, and estimate risk factors that could affect the reliability of the power system as we move towards an RTO. Identifying and solving major problems early reduces the likelihood of any negative impact on system reliability of moving from the present state to an RTO-operated system.

BPA engineer Bill Mittelstadt suggested that we consider a list of about a dozen factors that would be affected by an RTO. The authors of this section of the report expanded the list to around 46 issues, and prepared to analyze the reliability importance of each of these factors.

Finally, this is not a political document. This is a risk assessment, with suggestions on possible mitigations of risk. In making any change in organization, risk is involved in transition – even if every change were to ultimately be for the better. We believe we have identified the major risks in making a change to an RTO, and have also found some ways to mitigate the risks, so that, whatever decisions are made, a quality, reliable result is attained.

Local Factors Affecting System Reliability

Changing management of the Northwest Power Grid will not automatically increase the load carrying capability of the network shown in Figure 1. The Northwest Power Grid (Grid) is very different from East Coast grids in that it covers a larger geographical area with most large load centers being great distances from the major power generation sites. Transportation of power in the Northwest occurs across a highly utilized, high voltage system of power lines. Proper operation of this transmission system grid is paramount to reliability. The effect of poor grid care and operation can result in widespread blackouts.

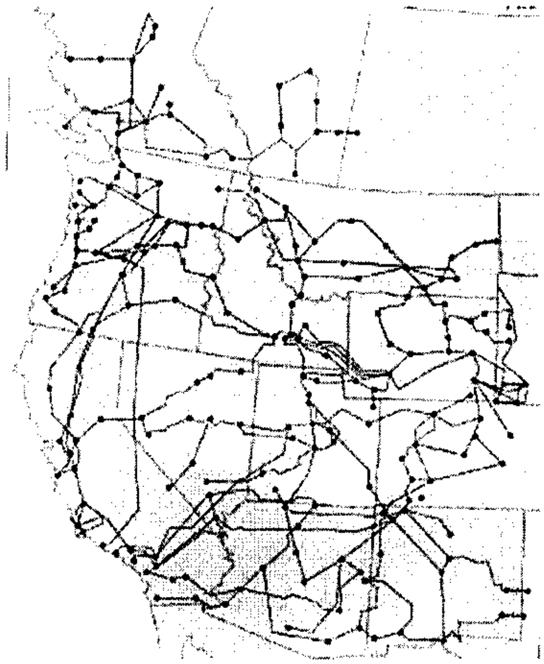

Figure 1 Map of Western States Major Transmission Lines

The large geographical area covered by the power grid means that the lines have great exposure to phenomena that can cause system faults (e.g., weather, vegetation overgrowth, etc.). When a line becomes faulted, the affected equipment must be removed from service. A single contingency loss of an apparatus must not destabilize the network such that the original disturbance cascades into the loss of an even greater portion of the power system. How the power system is operated and maintained has a great effect on how the utilities can localize and isolate only the effected apparatus.

How a power system responds to an incident depends largely upon many factors: generator loading, generator reserve, actions of the apparatus control systems and the dispatch operators. System reliability suffers when any part of this system fails to act properly.

For example, in 1996, the West Coast Power Grid suffered a severe disturbance. This disturbance affected thirteen states and provinces. The initiating event was really no different from many other previous incidents: a 500kV line faulted and was removed from service. For the next hour, the redistributed load currents overloaded lines. This eventually led to cascading outages.

Methodology

Ed Schweitzer (EOS) discussed possible methodologies of analysis with Ron Schwartz, Vice President of Quality at SEL. Ron suggested we apply the techniques of a Failure Mode Effects Analysis. In such an analysis, each issue is evaluated in three ways: severity, likelihood of occurrence, and likelihood of going undetected. Suppose we assign variables S, L and U, and then assign values to each variable for each issue. Then, for each issue, the risk priority is P = SLU.

EOS discussed this methodology with Ron Schwartz, and recommended a modified approach, not based on failure modes per se, and more suitable for comparing the relative effect of two different system designs and of transition from one system to a new one. In our case, the two system designs are the existing transmission operations, and a new operations with an RTO.

EOS and Ron Schwartz named the approach a Relative Reliability Effect Analysis. We decided to state a characteristic of an RTO, which contrasts it from today's organization; and then rate the reliability effect from –5 to +5, depending on whether the characteristic relatively reduces or increases reliability of the transmission system. We weighted each characteristic from 1 to 5, to rank the likelihood of occurrence, and multiplied the rates times the weights. So, each issue ended up with a possible score of from –25 to +25.

EOS collected a group of SEL personnel with the following backgrounds:

- Senior Protection Engineer, with experience at Bonneville Power Administration (BPA) and Pacific Gas & Electric (PG&E)
- Senior Protection Engineer, with experience at Chevron Oil Co. and PG&E
- Public Relations Manager, with legislative experience at the national and state levels, and with the benefit of recent experience concerning investigations into political activities involving utility deregulation
- Senior Electrical Engineer with experience in protection, metering, and research in several companies and at EPRI
- Senior Reliability and Quality Systems Engineer, with experience in a broad range of industries and organizations, including manufacturing, government, consulting and senior management
- Business Executive, familiar with all facets of SEL business, and years of experience tracking deregulation in our and other industries

EOS presented the following concepts to the group, so that the group had a common understanding of the present and the potential new situation (with the RTO), so that the two could be compared by the analytic method previously described.

FERC consists of presidential appointees. They mandated open access to transmission, and that four to five RTOs should cover the USA. The concept is a highly regulated "national grid" marketplace for unregulated generators to connect anywhere, to insert energy.

Distributors buy from the grid to resell energy to their end-users.

At present, in the RTO West area, there are about twelve electrically-interconnected utilities. They are relatively loosely coupled by interchange agreements.

Common issues are planned and discussed in the Western System Coordinating Council. Regional Coordinating Councils meet and plan at a national level via the North American Electric Reliability Council.

The concept under consideration for RTO West is a strong RTO. The utilities continue to own the assets, but RTO West operates the assets for the most part.

It is highly probable that NERC would set rigid standards for all RTOs to follow, and that these standards could some day have the force of law.

A web-based software system called OASIS (Open Access Same Time Information System) would be used for pricing and trading.

In summary, the RTO would centralize the planning and operation of most of the transmission assets still belonging to the individual companies.

Issues Evaluated in the Pullman Meeting

EOS reviewed the entire list of issues with the group described earlier. The purpose of reviewing the list first was so that all participants would have a broad enough perspective to assign relative weights to issues. He then led the group to consider each issue, one at a time, and assign a rate and a weight to each.

Table 1 lists the issues rated and weighted by the group, and shows the product of the rate and weight for each issue. Since our mission is to attempt to identify potential reliability issues, we took a critical point of view, looking for potential reliability impact in making the change. Therefore, most of the rated scores were negative.

For instance, "RTO puts capital where it does the most good" received a weight of 5, and a rating of –5, for a product of –25. The group's concern is that it could be a long time before RTOs, utilities, investment analysts, advisors, and FERC get everything figured out to the point where investors are again comfortable buying stock in utility transmission assets.

A positive example is "RTO develops on-line voltage and dynamic security tools," which received a weight of 3 and a rating of 3, for a product of +9. In our discussion particular to this point below, we note an RTO is not necessary to achieve this, however.

Strongly negative scores indicate the greatest risk factors the group foresees, and are the areas that should receive the most attention.

Within each of the eight categories, the lists are prioritized with the most significant negative impact on reliability listed first.

Table 1. Pullman Meeting Issue List

		Rate	Weight	Product
	Planning Characteristics of RTO			
1	RTO puts capital where it does most good	-5	5	-25
2	RTO operates safety nets to limit cascading	-4	4	-16
3	RTO develops system wide stability control measures	-3	3	-9
4	RTO reviews generation access request in timely manner	-2	2	-4
5	RTO screens entire system every two years	-2	1	-2
6	RTO determines safe operating limits	1	1	1
7	RTO collects system statistical data	1	1	1
8	RTO reports region load and resource data--poor now.	1	1	1
9	RTO applies uniform system-wide modeling	1	1	1
10	RTO applies uniform reliability criteria	0	1	0
11	RTO uses compatible, efficient planning tools	0	1	0
12	RTO develops system base case.	0	1	0
13	RTO recognizes need for long range planning	0	0	0
	Operations Characteristics of RTO			
14	RTO operators are familiar with system	-4	3	-12
15	RTO manages differences between plan and operations	-1	1	-1
16	RTO coordinates scheduled outages	-1	1	-1
17	RTO coordinates main grid with subtransmission system	0	0	0
18	RTO arms Remedial Action Scheme at right time	1	1	1
19	RTO determines safe operating limits	1	3	3
20	RTO develops and operates on-line voltage, dynamic security tools	3	3	9
	Maintenance Characteristics of RTO			
21	RTO standardizes ROW clearing	-2	2	-4
22	RTO develops uniform preventive maintenance practices	-1	1	-1
	Training Characteristics of RTO			
23	RTO has broader scope for operators	-3	2	-6
24	RTO has broader scope for maintenance	-3	2	-6
25	RTO has broader scope for planners	-3	2	-6
	Security Characteristics of RTO			
26	RTO is single point of control of InfoSec	-5	5	-25
27	RTO is additional point of InfoSec	-5	5	-25
28	RTO is new physical entity	-5	5	-25
29	RTO involves 200+ new people's trust	-5	5	-25
	Business Characteristics of RTO			
30	RTO is new operator of transmission	-5	5	-25
31	RTO attracts capital for new transmission	-4	5	-20
31	RTO responds to need for more transmission	-4	5	-20
32	People with knowledge from utilities who work for RTO will eventually retire.	-4	2	-8
33	RTO manages owner' assets per operating agreement (lease)	-2	2	-4
34	RTO is not as close to customer as utility	-2	2	-4
35	RTOs must protect propriety of data from individual utilities	-2	1	-2
36	RTO must protect propriety of generating company data.	-2	1	-2
37	RTO is non-profit agency	-1	1	-1
38	RTO requires new resources in utility to manage lease	-1	1	-1
39	RTO will hire and train 200+ new people.	-1	1	-1
	Political Characteristics of RTO			
40	RTO will be subject to political decision making (e.g. FERC)	-1	4	-16
41	RTO will be lobbied by suppliers, environmentalists, traders and generators	-3	4	-12
42	RTO scope of control in T and D is not clear yet	-2	3	-6
43	RTO will be lobbied by new transmission owners	-1	1	-1
44	RTO will be lobbied by other special interests	-1	1	-1

	Technical Characteristics			
45	RTO more dependent on communications	-3	3	-9
46	RTO will develop, own, operate voltage, stability and short-circuit models	-2	3	-6
47	RTO will write new technical standards for region	-1	1	-1

We next discuss the eight issues receiving the highest negative scores, indicating that these issues need the greatest amount of attention to avoid reliability problems. These eight issues are listed below, and then discussed.

I.	RTO Develops System Wide Stability Control Measures	-9
II.	RTO Operates Safety Nets to Limit Cascading	-16
III.	RTO Puts Capital Where It Does The Most Good	-25
IV.	RTO Operator System Familiarity	-12
V.	RTO Is A Single Point of Control for InfoSec	-25
VI.	RTO West is a New Entity	-25
VII.	RTO West Attracts Capital for New Transmission	-20
VIII.	Exertion of Outside Forces on the RTO	-12

I. RTO Develops System Wide Stability Control Measures

A single RTO office would handle a much greater amount of work than the individual utilities, and the office becomes a single point of failure.

Today, through their voluntary work with the Western System Coordinating Council (WSCC), individual utilities develop and implement stability control measures. Each utility has a vested interest in maintaining its part in maintaining system stability as failure to do so could affect them directly. Presently, there is a significant level of effort performed at the utility level by experienced personnel who collect, process, and interpret data from their portion of the power system.

In the beginning, the RTO will have relatively new staff. This new staff would need to review existing stability measures and possibly establish new ones. Even if each staff member has a high level of experience, it will take a year, perhaps more, for the group to function as a team.

Performing stability control requires a large amount of data. In addition to tracking and collecting data, the RTO staff would have to process and interpret the data. Computing programs could assist in this effort. However, interpreting data and transforming it into information is best performed by experienced personnel. As backup to the RTO, utilities should retain their personnel for maintaining and monitoring system stability.

Training, experience, and moving slowly while present systems are maintained and new ones are proven are possible mitigations.

II. RTO Operates Safety Nets to Limit Cascading

The concern with relying solely upon centralized safety net control is based upon the required level of expertise and system understanding.

Safety nets are mechanisms that a system relies upon to minimize a disturbance or stabilize a system. Left unchecked, the effect of these events can spread and disrupt large portions of the power grid. A properly designed safety net informs the system operator of line loading before it becomes critical. In an automatic mode, these intelligent systems remove apparatus or redistribute load to avoid the condition where the system operator must wait until a device thermally overloads.

In some instances, a broader system picture could assist with safety net operation. However, if sole control lies with an RTO and its resident experts, the system as a whole could lose the benefit of having regional experts and their close understanding of details inside regional systems. The loss of such knowledge and their vested interest in system operation would make the power system more fragile and therefore less reliable.

Mitigations include training and maintaining existing systems and staff until the new people and systems are proven.

III. RTO Puts Capital Where It Does The Most Good

The concept is that an RTO provides a systemwide vantage point from which capital allocations can be made wisely. (A later point discusses attracting capital.)

If the RTO gains an active role in capital allocation, it may slow down the process of planning and development, and possibly introduce new influences that may or may not be constructive. In the old days of vertical integration, capital planning of transmission, generation, and distribution occurred together in a region.

The model of capital planning today, and under an RTO, is indefinite, and therefore a risk factor. Mitigation is achieved by making it clear how capital allocations are simply, quickly, and easily made.

IV. RTO Operator System Familiarity

Power system operation requires input. Utility operators use data presented to them in a formal fashion at work, plus the informal inputs of living close to the assets they operate, e.g., local weather forecasts, driving by transmission lines, etc.

Today, utility operators are closer to the system than would be RTO operators. RTO operators would be responsible for a much larger power system than the present utility operator and would need to process even more data. The RTO operator could be overloaded by vast amounts of data from a much larger area and system. Although the wider purview suggests better decisionmaking, the system must be designed well so that operators can respond quickly to emergency conditions, without being slowed down by the larger scope and more data. Could an otherwise non-emergency condition become an emergency because of the delay caused by data overloading an RTO operator?

Presumably, the RTO would start with operators from the utilities beneath it. They would bring their experience from their parts of the system to the RTO. Without a training program, this expertise would decline over time, as people lose their familiarity with system details and as people retire or otherwise separate.

Mitigations beyond extensive training at the RTO include maintaining significant operating resources and training within the utilities.

V. RTO Is A Single Point of Control for InfoSec

Information security is critically important to the safe operation of an RTO. Information and control actions need to move around a region of 50 million people; thus, the RTO becomes a prime target of information operations, information warfare, hackers, disgruntled employees, frustrated customers, etc. The RTO must be designed from the very beginning with the highest degree of communications and information security.

Redundancy is a two-edge sword. On the positive side, with two systems, one can fail and the other continues to operate. The negative side is that two systems mean two ways in.

VI. RTO West is a New Entity

RTO West will be a new organization, and there will be some successes and some failures as the organization takes form, people are trained, leadership is developed, and processes are developed, measured, and improved.

The processes not only include the work of running the transmission system, but also physical security, training programs, background screening of new employees, etc.

Mitigating these risks requires a slow, careful transition from existing people, processes and systems to new ones.

VII. RTO West Attracts Capital for New Transmission

The author discussed investing in utility stocks with a utility analyst at a major banking institution. The analyst advised that FERC is considering 13% profits in the Midwest, and this would be, in the analyst's opinion, a very attractive return. However until we really know how much profit the federal government will let these business entities make, and exactly how utilities are going to get paid, we must consider this issue a very high risk for power system reliability.

Speakers at the National Transmission Group Study (NTGS) workshops in Detroit, Atlanta and Phoenix have asked how the transmission system would attract capital. FERC is still considering policies of profitability in transmission.

The presenters at all three NTGS Workshop meetings saw capitalization as a serious matter. Attracting capital for improving the transmission infrastructure dominated the topics and questions in all three meetings. The industry needs to attract capital to construct new transmission lines to ensure system reliability and to achieve the goal of "open transmission."

There is no reason to expect that establishing an RTO will solve the problem of attracting capital for the new transmission we need right now. Anticipating that an RTO might help solve this problem may delay the real solutions.

Capital will flow to transmission once investors are satisfied in the balance between risk and return. The author believes a key to this is a stable business environment, where investors feel that the political factors have settled down, and where the business models are easily understood.

VIII. Exertion of Outside Forces on the RTO

RTO West will control the power system grid serving tens of millions of people. Such a power base attracts those wishing to influence the policies and decisions of RTO West.

RTO West personnel will receive input for decision making concerning routing and construction of new transmission lines, upgrading existing lines, placement of new generation, etc. We see this occurring with much the same process as new legislation where lobbyists provide input. Other possible sources of influence are:

- Power Traders: Influencing line placement could benefit certain traders.
- Environmentalists: Again, line placement is a critical concern.
- Generation Companies: Siting is very important. When new generation is brought on-line, the corresponding utility apparatus must be in-place to make efficient use of the new power.
- Federal Government (FERC): RTO West decisions and actions must be to advance and maintain the power system.

Thus the RTO becomes a new point of influence, in addition to the existing regulatory agencies and utilities.

This is very difficult to mitigate. Perhaps the best way is to ensure that any function assigned to the RTO is truly essential at that top level—thereby minimizing the number of dimensions of influence.

Conclusions

From a point of view of reliability, we have considered many factors and issues, and have identified eight as key considerations in possible reliability impact. We have suggested some ways to mitigate risk. Moving to a new top-level organization does involve transitional reliability risk, such as new systems, people, and training. There are some ongoing risks, such as the information and physical security risks that are heightened; and expecting an RTO to solve the capital-attraction problems of today's industry would only delay the solution of this key issue in building, operating, and maintaining a reliable transmission system.

As the table shows, there are some positive gains for reliability. For these to surface, we must proceed carefully to mitigate the other areas of risk.

BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

Avista Corporation,	)	
Bonneville Power Administration,	)	
Idaho Power Company,	)	
The Montana Power Company,	)	
Nevada Power Company,	)	Docket No. RT01-35-005
PacifiCorp,	)	
Portland General Electric Company,	)	
Puget Sound Energy, Inc., and	)	
Sierra Pacific Power Company.	)	

Affidavit of Lon L. Peters, Ph.D.

I, Lon L. Peters, Ph.D., do hereby depose and say:

1. I am a consulting economist and the President of Northwest Economic Research, Inc. I have worked in the energy industry, mainly in the Northwest, for almost 20 years. My business address is 6765 S.W. Preslynn Drive, Portland, Oregon 97225. My educational background includes the Ph.D. degree in economics, received from Yale University in 1981. I have been retained by the Public Generating Pool, members of Protestants in this docket, to provide analysis and advice regarding the implications of the RTO West Stage 2 proposal for consumers.

2. This affidavit attests to the content of discussions held in March and May 2002, among myself, representatives of Tabors Caramanis and Associates (TCA), and representatives of other interested parties, regarding certain assumptions made by TCA in the preparation of the "RTO West Benefit/Cost Study", March 11, 2002.

3. On March 20, 2002, I participated in a meeting of the "benefit-cost work group", held at the offices of the Public Power Council, in Portland, Oregon. According to my notes and a sign-in sheet, approximately 19 individuals were present at the meeting,

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either in person or by telephone. One of the purposes of the meeting was to review the Energy Analysis conducted by TCA for the RTO West Filing Utilities.

4. According to my written notes of the March 20 meeting, TCA representatives stated that the contractual rights to shares of non-federal Mid-Columbia hydroelectric projects that are held by Northwest investor-owned utilities (IOUs) were excluded from the list of generation resources assumed to be available to such IOUs for the purpose of providing operating reserves in the computer model used to calculate the Energy Analysis.

5. On May 21, 2002, I participated in a meeting held at Clark Public Utilities, Vancouver, Washington. Representatives of BPA, TCA, and BPA customers were present either in person or by phone. According to my recollection, there were approximately ten participants in this meeting. One of the purposes of the meeting was to continue discussion and clarification of the TCA Energy Analysis conducted for the RTO West Filing Utilities.

6. According to my written notes of the May 21 meeting, TCA representatives confirmed that they had relied on information provided by BPA to limit the amount of hydroelectric generating resources that would be assumed to be available for the provision of operating reserves in the Energy Analysis. During the course of the meeting, the application of the "20 percent rule" was clarified. The example provided by BPA staff during the meeting suggested that 20 percent of installed hydroelectric generating capacity would be normally available for operating reserves, because hydro units are normally operated at 80 percent of capacity for efficiency purposes. In contrast, TCA assumed that only 20 percent of <u>unloaded</u> capacity would be

available for operating reserves in the Energy Analysis. The specific example of a 100 MW unit was used to clarify this distinction.

7. At the May 21 meeting, TCA representatives also stated that they assumed that "new" combined-cycle combustion turbines (CCCTs) would <u>not</u> rely on long-term transmission contracts for the delivery of power to consumers, but would instead rely on hourly purchases of transmission capacity. By "new", I understood TCA to mean those CCCTs that are under construction at the present time or are otherwise expected to be in operation by 2004.
8. At the May 21 meeting, TCA representatives also described the change in congestion costs as a "transfer" payment.

DATED this 27th day of May, 2002.

By: ______________________
Lon L. Peters, Ph.D.

STATE OF OREGON)
) ss.
County of Multnomah)

Signed and sworn to (or affirmed) before me this 27th day of May 2002, by Lon L. Peters, Ph.D.

OFFICIAL SEAL
ALAINA L BOGLE
NOTARY PUBLIC-OREGON
COMMISSION NO. 343573
MY COMMISSION EXPIRES APRIL 18, 2005

____
NOTARY PUBLIC FOR OREGON
My Commission Expires: 4-18-05

May 21, 2002

Response to Snohomish Tax Analysis

1. The Filing Utilities have been aware of potential state tax issues from the beginning of their efforts to form RTO West. They have been especially aware of the issues surrounding the potential application of certain Washington State taxes --the Public Utility Tax, the Business and Occupation Tax and the Leasehold Excise Tax -- to RTO West's relationship to the Federal Columbia River Transmission System. They are also aware of the recent application of Oregon property taxes to the purchase of a capacity "share" of Federal transmission facilities. The Filing Utilities have structured their RTO West proposal to minimize additional tax burdens.

2. The Filing Utilities have reviewed the April 23, 2002 "Analysis of Tax Implications of RTO West in Washington and Oregon" prepared for Snohomish County PUD ("Snohomish tax analysis"). That analysis concluded that incorporation of the assets of the Federal Columbia River Transmission System into RTO West was "likely to create significant new tax liability" in Oregon and Washington of over $150 million annually. The Filing Utilities believe that the Snohomish tax analysis ignores critical structural and legal characteristics of the proposed relationship between RTO West and Federal transmission facilities which, when incorporated into the analysis, lead to very different conclusions. For example:

- Public Utility Tax/Business & Occupation Tax: Under the RTO West Transmission Operating Agreement, RTO West would have "no ownership interest in the proceeds or receivables of the amounts billed by RTO West as billing agent" for the Participating Transmission Owners (PTOs), including Bonneville. (Transmission Operating Agreement, §17.3.7). RTO West will act as billing agent for Company Rates, any successor rates, Transfer Charges, External Interface Access Fees and applicable Wholesale Distribution Rates. The PTOs explicitly retain ownership of these revenues in order to continue covering their costs. RTO West would have rights only to the revenues from the Grid Management Charge and any other charges intended to cover RTO West's own costs.
    - Transmission customers will make payments of Company Rates, any successor rates, Transfer Charges, External Interface Access Fees and applicable Wholesale Distribution Rates to a Paying Agent (likely a bank) who will hold them in trust for the benefit of, and directly allocate them to, the appropriate PTO owner. (In order to avoid a bond default, BPA's net billing customers must continue to make power and transmission payments directly to Energy Northwest, as they do today, until annual net billing obligations are satisfied.)
    - Thus, the bulk of the "gross revenues" or "gross income" would remain the property of the PTOs, and RTO West would have no interest in or access to these receipts. Neither the Washington Public Utility Tax nor the Business and Occupation Tax would likely be applied to RTO West with respect to revenues which remain federal property.
    - Consequently, even if the Public Utility Tax or Business and Occupation Tax were applicable to RTO revenues (and the filing utilities believe neither tax may apply), the amount of taxable revenue would be minimized.

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- Leasehold Excise Tax: By joining the RTO, Bonneville Power Administration will not grant an ownership or leasehold interest in federal transmission assets to RTO West. No payments will be made by RTO West to Bonneville as consideration for any ownership or leasehold interest. The legal relationship between RTO West and Bonneville would be better described as that of an independent contractor and its principal. RTO West will perform certain transmission functions for BPA as a government contractor.
    - Bonneville's legal authority to participate in RTO West is based upon its authority to contract with others to carry out its functions. ("Bonneville Power Administration Authority to Participate in an Independent System Operator," Memorandum of U.S. Department of Energy General Counsel, February 26, 1998). To ensure that RTO West carries out Bonneville's functions, the contract between Bonneville and RTO West must incorporate (1) performance standards regarding implementation of its statutory, contractual and treaty obligations and (2) BPA authority to terminate the contract for RTO West's failure to comply with its requirements.
    - Reciprocally, Bonneville would agree to accept operational and scheduling directives from RTO West. Such directives would be sent from an offsite RTO West facility to the Bonneville operators and must comply with various standards established by Bonneville and the other PTOs. Bonneville employees would continue to operate the Bonneville system in accordance with the Transmission Operating Agreement with RTO West. Bonneville retains the authority to refuse to implement the directives in specific situations, including when it believes a directive could endanger its facilities, human safety or its compliance with applicable laws or regulations.
    - The Transmission Operating Agreement is terminable by Bonneville (1) at will upon two years notice and (2) immediately for a variety of reasons.
    - Thus, RTO West would have no possessory or other legal interest in any federal poles or wires. Consequently, there would likely be no "possession and use" of PTO facilities by RTO West as is required for the application of the Washington State leasehold excise tax.
    - Even if "possession and use" of PTO transmission facilities were found to exist, the Washington tax regulations exempt "use or occupancy of public property where the purpose of such use or occupancy is to render services to the public owner . . . in furtherance of the public owner's purposes." (WAC 458-29A-100). RTO West would be contracting with Bonneville to carry out Bonneville's statutory, contractual and treaty responsibilities. Notably, RTO West is explicitly prohibited from adding any charges to a PTO's revenue requirement, including that of Bonneville, to provide RTO West or any other party with a profit or return on the PTO's assets. (Transmission Operating Agreement, §17.1)
- Oregon Property Tax: There would likely be no "possession" of Bonneville facilities or transmission capacity by RTO West as is required for the application of Oregon property taxes. Bonneville would transfer no ownership-like interest to RTO West like the interest it transferred to a cooperative in *Power Resources Cooperative v. Dept. of Revenue,* 330 Or 24 (2000). In that case, BPA sold a 50 MW "share" of Southern

Intertie capacity under a "life of facilities" contract in exchange for payments to finance construction of that facility and annual payments of a proportionate share of the cost of operating and maintaining that facility. The cooperative was free to schedule power over that capacity for its own benefit—to import and export power owned by the cooperative or to provide wheeling services to others in exchange for payments to which it had ownership rights. The Oregon Supreme Court recently held that transfer to be subject to Oregon property taxes. Contrary to the ownership terminology used by the court in that case:

- RTO West would not be "investing" in the system either to purchase a "share" or to purchase the entire capacity;
- RTO West would not be obligated to pay a share of federal system costs;
- the relationship would not be created for RTO West to transmit electricity for its "own benefit;"
  - RTO West would not be allowed to "use [the transmission capacity] in whatever manner it wishes." It would be required to carry out its obligations for the benefit of others pursuant to the Transmission Operating Agreement, including meeting the obligations of Bonneville's pre-existing transmission agreements with others. RTO West will not schedule power transactions for its own benefit as it is required to be independent of merchant functions.
- receipts for wheeling services would not be owned by RTO West;
- the Transmission Operating Agreement is "revocable" by Bonneville;
- the restrictions and limitations of the relationship between RTO West and Bonneville are not "the kind . . . that joint owners or lessees of this kind of property would impose on themselves in the interest of orderly operation;"

3. The Filing Utilities do not agree with the Snohomish tax analysis that the Washington State use tax is likely to be applied under the "bailment" provisions. The relationship between RTO West and Bonneville is not likely to be determined to be a bailment because RTO West will not "actually take[] possession of the property" as is required by Department of Revenue rules. WAC 458-20-211(3). Even if it were determined to be a bailment, the use tax is applied only to bailments of tangible personal property, RCW 82.12.020(1), whereas the federal transmission system is composed primarily of fixtures.

4. The Snohomish tax analysis suggests that significant new state taxes may be imposed on the Paying Agent. The Paying Agent performs an escrow function. It receives funds in trust for specified beneficiaries, but has no legal interest in revenues passing through its hands. These functions are usually performed by a bank through its trust department. These services are very low cost and unlikely to give rise to any significant tax increase.

5. The Filing Utilities believe that state taxes would more likely be applied to the much smaller amounts of (1) RTO West property (control center, office building and equipment, computer hardware, and software, etc.) and (2) those revenues to which RTO West had a right and for which there is no exception or deduction under applicable law. The Filing Utilities also agree that state taxes could apply to certain transactions of Scheduling Coordinators. Of course, the largest Scheduling Coordinator in the region is likely to be Bonneville, which would not be

subject to such taxes. The next largest Scheduling Coordinators in the region are likely to be investor owned utilities who are already subject to state taxation. New businesses formed to perform Scheduling Coordinator functions may be subject to state taxes.

6. For further information, contact Steve Larson, BPA attorney, (503)-230-4999.

Exhibit 6

Summary of Costs and Benefits of RTO West

		(millions)	Notes
TCA Analysis for Filing Utilities			
Estimate of Net Benefits from Energy Analysis	$	410	1/
Less Avoided Congestion Rent Transfers	$	(171)	2/
= Estimate of Reduced Production Costs	$	239	
Estimated Corrections to Production Cost Savings in TCA Analysis			
Maintenance Scheduling Ignores Market Conditions	$	(27)	3/
Operating Reserves Overstate Reliance on Thermal Resour	$	(150)	4/
New Costs Identified by TCA			
Optimistic Estimate of New Costs of RTO West	$	(127)	5/
Lower Estimate of SC Costs	$	(17)	6/
Estimate of Exchange Costs	$	(27)	7/
= Net Economic Benefits to Consumers	$	(110)	
Additional Costs and Risks			
Potential Overruns on New Costs of RTO West	$	(64)	8/
Upper Estimate of SC Costs	$	(5)	9/
New Metering Costs	$	(12)	10/
New Paying Agent Costs	$	(3)	11/
New Transactions Costs	$	(41)	12/
Additional Return-on-Equity for IOUs	$	(28)	13/
Additional State and Local Taxes	$	(183)	14/
Risk of Market Power		??	
Risk of Reduced Reliability		??	
Risk of Delays in Construction of New Transmission Capac		??	
Risk of Additional Insurance Costs		??	
Cost of New Credit Standards		??	

EXHIBIT 6

Exhibit 6

Summary of Costs and Benefits of RTO West

Congestion Management Reserve Account		??	
Potential Net Cost to Consumers	$	(445)	15/

Notes

1/ TCA Final Report at vii
2/ TCA Final Report at viii; eliminated because "avoided congestion rents" are a transfer, not an economic cost
3/ TCA Final Report at 27 (change in savings for "same maintenance schedule" case)
4/ TCA Final Report at 27 (change in savings for "operating reserves" case)
5/ TCA Final Report at 39
6/ TCA Final Report at 44
7/ TCA Final Report at 43
8/ 50% overrun, or one-half of difference between low TCA est. and 2002 Cal-ISO
9/ TCA Final Report at 44
10/ $50,000 per node; 2,735 nodes; amortized @ 8% for 30 years
11/ $0.01/MWH times RTO West load
12/ $0.15/MWH times RTO West load (1/4 of anecdotal evidence on California)
13/ 230 basis points on $1.2 billion in net book value
14/ Midpoint of Lane, Powell annual range + 10% of lump-sum
15/ Net Economic Benefits + Corrections + Omitted Quantified Costs

Load Data for Notes 10 and 11

TWH	274,652
aMW	31,353
MWH	274,652,000
Source:	TCA Final Report, Appendix 1 at 88; all RTO West lines except Chelan/Douglas/Grant.

Exhibit 6

Summary of Costs and Benefits of RTO West

ROE Data for Note 12

2.30%	Weighted average increase in ROE requested for PGE, Nevada Power, and Sierra Pacific in FERC Docket No. ER01-___-000 under TransConnect proposal
	Source: Calculated from Exhibit TC-2, Testimony of James Piro
Net book	$1.2 billion in 2004
	Source: Exhibit TC-9, Testimony of David Patton

Other Calculations

kWh	274,652,000,000	
Savings	$62,000,000	
$/kWh	$0.000226	
Ave. rate	$0.05	per kWh
% saved	0.45%	

Source: BPA OASIS

Request Number: 85

Requester: Power Exchange Corporation (Powerex)

Date & Time of Request: Received by the Bonneville Power Administration Transmission Business Line (TBL) on March 17, 1999 at 1508 hours.

Type of service requested: Point-to-Point (PTP) Transmission Service

Requested commencement date of service: May 1, 2002

Requested termination date of service: September 1, 2003

Quantity: May 300 MW, Jun-Aug 400 MW, Sep-Apr 1 MW, May-Aug 400 MW

Price: IS-96 Rate

Point of receipt: Big Eddy

Point of delivery: Nevada-Oregon Border (NOB)

Place of the request in the queue: March 17, 1999 at 1508 hours

Status of the request: Approved contract signed April 29, 1999

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LANE
POWELL
SPEARS
LUBERSKY
LLP

MEMORANDUM

May 24, 2002

TO: Eric Christensen
Associate General Counsel
Snohomish County PUD

FROM: George C. Mastrodonato
John H. Gadon

RE: RTO West Tax Analysis

You have requested our general thoughts regarding the Bonneville Power Administration's ("BPA") Response to Snohomish Tax Analysis dated May 21, 2002 (the "BPA Response"). The BPA Response was prepared in response to the state tax analysis set forth in our memorandum dated April 23, 2002.

Pursuant to your request, this statement presents only our general overview and does not attempt to analyze the legal theories and arguments outlined in the May 21 response or to evaluate all relevant factual developments. Accordingly, this statement should not be taken as a legal analysis or opinion on any of the issues discussed below.

A. Overview.

Having reviewed the BPA Response, and subject to the assumptions and qualifications set forth in our original memorandum, we continue to believe that our analysis represents a reasonable estimate of the risk and extent of the potential Oregon and Washington state tax liability associated with transferring control over BPA's transmission system to RTO West.

Our analysis of the Oregon and Washington State tax implications of RTO West was explicitly and inherently based on four fundamental assumptions. First, full operational control of the BPA transmission system would be assumed by RTO West. Second, tax officials in both Oregon and Washington would view the RTO West transmission operating agreement and related agreements under the rule that substance will control over form in tax classifications. *Portland General Electric Co. v. Department of Revenue*, 11 OTR 78, 82-83 (Or. Tax 1988) ("[A]ll transactions are to be judged by their substance rather than their form to determine their tax effects"); *Stuart v. Department of Revenue*, 6 OTR 389, 398 (Or. Tax 1976); *aff'd*, 278 Or. 623, 565 P.2d 733 (1977) ("[I]t must be observed that all tax laws ... look to the substance rather than

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the form of the transaction."); *Shull v. Commission*, 1 OTR 445, 453 (Or. Tax 1963) ("This court is in full agreement that the law should look beyond the form to the substance of the transaction."); *First American Title Insurance Company v. Department of Revenue*, 144 Wn.2d 300, 303, 27 P.3d 604 (2001) ("Substance rather than form should be used to assess tax classifications"); *Time Oil Company v. State*, 79 Wn.2d 143, 147, 483 P.2d 628 (1971) (court refuses "to exalt form over substance" to determine taxable status of transaction). Third, this is a highly unusual and unique business arrangement for which there are no legal precedents directly on point. As it is well established in both Oregon and Washington that tax exemptions are to be strictly and narrowly construed, caution was exercised in applying tax exemption statutes. Fourth, this is a matter of first impression in both Oregon and Washington and a substantial amount of property value (and therefore potential property tax) is at stake. Tax officials in both states would be cautious in granting any tax exemptions. With these general assumptions in mind, our specific reply to the BPA Response to the Snohomish County PUD tax analysis follows.

B. <u>Washington Taxes</u>.

1. **<u>Washington Public Utility Tax/B&O Tax</u>**. The principal contention made here by BPA is that RTO West would have no ownership interest in the revenues billed for various transmission services because RTO West would be merely a billing agent for the various Participating Transmission Owners (PTOs). We believe it is highly speculative to conclude that Washington tax officials would accept RTO West as a mere agent when it exercises operational control over all the transmission assets. The result sought by BPA is still speculative even though an affiliation with a Paying Agent is allegedly designed to create a third-party agency to collect the revenues. Because the Paying Agent will likely be under the control of RTO West, receipt by the Paying Agent is arguably constructive receipt by RTO West. While there may be contractual language creating an agency relationship as between the PTOs and the Paying Agent, or even between the PTOs and RTO West, contract language is not determinative. *Rho Co., Inc. v. Department of Revenue*, 113 Wn.2d 561, 563, 782 P.2d 968 (1989). As such, it may not make any difference that the Paying Agent holds the funds in trust or that it directly allocates the funds to a particular PTO. Thus, because RTO West will have operational control of the transmission system, arguably, the receipts for the transmission services will be attributed to it.

2. **<u>Leasehold Excise Tax</u>**. The leasehold tax will be imposed in Washington on any agreement for the transfer of property between a public owner and a person who would not be exempt from property taxes if the person owned the property in fee, granting possession and use, to a degree less than fee simple ownership. RCW 82.29A.020(1) and .030(1). The leasehold tax statute is very broad in its coverage and is intended to cover most uses of public property by private parties. *See* RCW 82.29A.010. The RTO West-BPA relationship is unique. Nevertheless, there appears to be a sufficient transfer by BPA and control over the assets by RTO West to fall within the definition of leasehold interest under the statute, and so the application of the leasehold tax cannot be ruled out. Our assumption is, and has been, that the transfer of rights in BPA-owned assets is sufficient to create a leasehold interest under the broad language of the statute.

3. **Bailment/Use Tax**. A bailment arises under Washington law when one party uses personal property of another, no consideration is exchanged between the parties, and the property in question has not been subjected to a sales or use tax. *See* RCW 82.12.010(1)(b). We were given insufficient information to form a definitive conclusion as to what BPA assets would be considered real or personal property under Washington law (*see Lipsett Steel Products, Inc. v. King County*, 67 Wn.2d 650, 652, 409 P.2d 475 (1965) (ascertaining whether improvements to land "have become, in legal contemplation, a part of the realty" requires "the united application of these requisites: (1) Actual annexation to the realty, or something appurtenant thereto; (2) application to the use or purpose to which that part of the realty with which it is connected is appropriated; and (3) the intention of the party making the annexation to make a permanent accession to the freehold", citing *Foreman v. Columbia Theater Co.*, 20 Wn.2d 685, 148 P.2d 951 (1944)), and so our assumptions on the use tax were intended as somewhat of a "worse case" scenario. Nevertheless, we still believe the conclusion that use tax will apply to personal property assets is valid because RTO West will have sufficient possession of the assets to create a bailment situation under Washington law.

C. **Oregon Taxes.**

1. **Property Tax**. Under Oregon law, an "ownership" interest of federal property is not required for the property to become taxable. Rather, any real or personal property of the United States or an agency thereof that is held by a person under "*a lease or other interest or estate less than a fee simple*" is subject to Oregon property tax. ORS 307.060. The fact that others (including the owner) may also have rights in the property or that there are limitations on the contracting party's use of the property is not determinative, provided that those rights and limitations are not inconsistent with the contracting party's contemplated use of the property. *Avis Rent A Car System, Inc. v. Department of Revenue*, 330 Or. 35, 995 P.2d 1163 (2002); *Sproul v. Gilbert*, 226 Or. 392, 404-06, 359 P.2d 543 (1961).

The operative question under Oregon law is whether RTO West would have sufficient rights with respect to the transmission system for the system to be treated as taxable property.

Under the March 29, 2002 draft of the transmission operating agreement, RTO West would have exclusive operational control over the transmission system. It would also have the right to expand and upgrade the system and to direct control of certain system critical facilities. Furthermore, each transmission facility owner would not have the right to transfer or assign any transmission assets unless the transferee agreed to be bound by the terms of the transmission operating agreement on the same terms as the transferor. Taking into account the entire bundle of rights given to RTO West under the transmission operating agreement, we believe that there is substantial risk that the Oregon Department of Revenue and Oregon courts would conclude that RTO West has a sufficient interest in the transmission system for the system to become subject to tax.

BPA's Response attempts to distinguish the Oregon Supreme Court's decision in the *Power Resources* case by pointing out factual differences between the facts presented in that case and the proposed agreement with RTO West. Yet these factual differences are simply irrelevant to the issue of whether the BPA transmission assets over which RTO has control would become taxable. There is no requirement under Oregon law that for federal property to become taxable, the user of the property "invest" in the property or be obligated to pay any share of its upkeep. Furthermore, the fact that BPA would have the right to terminate the agreement with two years notice doesn't distinguish the agreement from most interests in property that are less than fee simple. *See generally Sproul v. Gilbert*, 226 Or. at 406 ("The revocability of the occupant's interest is not a controlling factor in classifying it as a possessory or non-possessory interest."). *Accord: Oregon Summer Home Owners Association v. Johnson,* 265 Or. 544, 549, 510 P.2d 344 (1973).

Finally, as noted in our April 23 memorandum, RTO West is likely to be taxed as a utility for Oregon property tax purposes. As a utility, RTO West would be taxed on its property as an operating unit, including any property "used" by RTO West in the performance of its business and on any intangible property. ORS 308.510(1). Under this statute, there is a substantial risk that RTO West could be taxed on the transmission system even without regard to whether it possessed a taxable interest in the system under ORS 307.060.

2. Corporation Excise Tax/Paying Agent.

The Oregon tax analysis with respect to the taxability of the income received by the Paying Agent under the state corporation excise tax and local taxes on net income is similar in many respect to the analysis with respect to the analysis for the Washington public utility and B&O taxes.

The threshold question is whether the a characterization of RTO West as merely a billing agent and the Paying Agent as an agent of the utilities (rather than solely an agent of RTO West) would be respected. As noted previously, Oregon courts follow the substance over form doctrine. Oregon courts are not bound by the parties' own characterization of a transaction in applying tax statutes. *Warm Springs Lumber Co. v. Horn*, 217 Or. 219, 225, 342 P.2d 143 (1959). *See also Sproul v. Gilbert*, 226 Or. at 402.

In addition, the proposed structure raises significant potential assignment of income issues. *See Department of Revenue v. Rombough*, 293 Or. 477, 650 P.2d 76 (1982); *Cole v. Department of Revenue*, 9 OTR 227 (Or. Tax 1982).

We therefore continue to believe that, under the current proposed structure, there is a significant risk that RTO West could have substantial state and local income tax exposure.

Complete Listing of Protestants

Public Generating Pool
Cowlitz County Public Utility District
Douglas County Public Utility District
Grant County Public Utility District
Pend Oreille County Public Utility District
Seattle City Light

Washington Public Utility Districts Association
Asotin County Public Utility District
Benton County Public Utility District
Chelan County Public Utility District
Clallam County Public Utility District
Clark Public Utilities
Cowlitz County Public Utility District
Douglas County Public Utility District
Ferry County Public Utility District
Franklin County Public Utility District
Grant County Public Utility District
Grays Harbor County Public Utility District
Kittitas County Public Utility District
Klickitat County Public Utility District
Lewis County Public Utility District
Mason County Public Utility District No. 1
Mason County Public Utility District No. 3
Okanogan County Public Utility District
Pacific County Public Utility District
Pend Oreille County Public Utility District
Skamania County Public Utility District
Snohomish County Public Utility District
Wahkiakum County Public Utility District
Whatcom County Public Utility District

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Western Public Agencies Group
Alder Mutual Light Company
Benton Rural Electric Association
City of Cheney
City of Ellensburg
City of Fircrest
City of Milton
City of Port Angeles
Elmhurst Mutual Power and Light Company
Lakeview Light and Power Company
Ohop Mutual Light Company
Parkland Light and Water Company
Peninsula Light Company
Public Utility District No. 1 of Clallam County, Washington
Public Utility District No. 1 of Clark County, Washington
Public Utility District No.1 of Kittitas County, Washington
Public Utility District No. 1 of Lewis County, Washington
Public Utility District No. 1 of Mason County, Washington
Public Utility District No. 3 of Mason County, Washington
Public Utility District No. 2 of Pacific County, Washington
Public Utility District No. 1 of Snohomish County, Washington
Town of Eatonville
Town of Steilacoom

Public Utility District No. 1 of Snohomish County

Springfield Utility Board

Tacoma Power

Eugene Water and Electric Board

CERTIFICATE OF MAILING (SERVICE LIST)

I HEREBY CERTIFY that I have this day served the foregoing, PROTEST OF THE PUBLIC GENERATING POOL, the WASHINGTON PUBLIC UTILITY DISTRICTS ASSOCIATION, the WESTERN PUBLIC AGENCIES GROUP, PUBLIC UTILITY DISTRICT NO. 1 OF SNOHOMISH COUNTY, SPRINGFILED UTILITY BOARD, TACOMA POWER, and the EUGENE WATER and ELECTRIC BOARD on the FILING UTILITIES' STAGE 2 FILING and REQUEST FOR DECLARATORY ORDER PURSUANT TO ORDER 2000 to be served by First Class Mail upon each party designated on the official service list compiled by the Secretary of the Commission in this proceeding.

DATED at Portland, Oregon, this 28th day of May, 2002.

Raymond S. Kindley

Raymond S. Kindley